CONCHO RESOURCES INC
Form 10-K
February 21, 2018

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2017

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ____________________ to ____________________

Commission file number: 1-33615

Concho Resources Inc.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**76-0818600** (I.R.S. Employer Identification No.)
One Concho Center **600 West Illinois Avenue** **Midland, Texas** (Address of principal executive offices)	**79701** (Zip Code)

(432) 683-7443
(Registrant's telephone number,
including area code)

Securities Registered Pursuant to
Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $0.001 par value	**New York Stock Exchange**

Securities Registered Pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o
Emerging growth company o	

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter:	$17,883,517,337
Number of shares of the registrant's common stock outstanding as of February 16, 2018:	149,067,852

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2018 Annual Meeting of Stockholders, which will be filed with the United States Securities and Exchange Commission within 120 days of December 31, 2017, are incorporated by reference into Part III of this Form 10-K for the year ended December 31, 2017.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements and information contained in or incorporated by reference into this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (the “Exchange Act”). These forward-looking statements include statements, projections and estimates concerning our future financial position, operations, performance, business strategy, oil and natural gas reserves, drilling program, capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as “estimate,” “project,” “predict,” “believe,” “expect,” “anticipate,” “potential,” “could,” “may,” “foresee,” “ “goal” or other words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. We have based these forward-looking statements on our current expectations and assumptions about future events and their potential effect on us. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Actual results may differ materially from those implied or expressed by any forward-looking statements. These forward-looking statements speak only as of the date of this report, or if earlier, as of the date they were made. We disclaim any obligation to update or revise these statements unless required by law, and we caution you not to rely on them unduly. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks discussed in “Item 1A. Risk Factors” in this report, as well as those factors summarized below:

- declines in, or the sustained depression of, the prices we receive for our oil and natural gas;

- uncertainties about the estimated quantities of oil and natural gas reserves;

- the costs and availability of equipment, resources, services and qualified personnel required to perform our drilling, completion and operating activities;

- disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver our oil, natural gas liquids and natural gas and other processing and transportation considerations;

- drilling, completion and operating risks;

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;

- risks related to the concentration of our operations in the Permian Basin of southeast New Mexico and west Texas;

- risks associated with acquisitions, including liabilities associated with acquired properties or businesses and the ability to realize expected benefits;

- the effects of government regulation, permitting and other legal requirements, including new legislation or regulation related to hydraulic fracturing, climate change, derivatives reform or the export of oil and natural gas;

- the impact of current and potential changes to federal or state tax rules and regulations, including the Tax Cuts and Jobs Act;
- potential financial losses or earnings reductions from our commodity price risk-management program;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our credit facility;
- the impact of potential changes in our credit ratings;
- uncertainties about our ability to successfully execute our business and financial plans and strategies;
- evolving cybersecurity risks, such as those involving unauthorized access, denial-of-service attacks, malicious software, data privacy breaches by employees, insiders or others with authorized access, cyber or phishing-attacks, ransomware, malware, social engineering, physical breaches or other actions;
- uncertainties about our ability to replace reserves and economically develop our current reserves;
- general economic and business conditions, either internationally or domestically;
- competition in the oil and natural gas industry; and
- uncertainty concerning our assumed or possible future results of operations.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and the price and cost assumptions made by our reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered.

PART I

Item 1. Business

General

Concho Resources Inc., a Delaware corporation ("Concho," the "Company," "we," "us" and "our") formed in February 2006, is an independent oil and natural gas company engaged in the acquisition, development, exploration and production of oil and natural gas properties. Our core operations are primarily focused in the Permian Basin of southeast New Mexico and west Texas. The Permian Basin is one of the most prolific oil and natural gas producing regions in the United States and is characterized by an extensive production history, long reserve life, multiple producing horizons and enhanced recovery potential. Currently, the majority of the rigs running in the Permian Basin are drilling horizontal wells. Concho's legacy in the Permian Basin provides us a deep understanding of operating and geological trends. We are actively developing our resource base by utilizing extended length lateral drilling, enhanced completion techniques, multi-well pad locations and large-scale development projects throughout our four core operating areas: the Northern Delaware Basin, the Southern Delaware Basin, the Midland Basin and the New Mexico Shelf. Our strategy remains focused on development and exploration activities on our multi-year project inventory and pursuing acquisitions that meet our strategic and financial objectives.

Business and Properties

Our core operations are focused in the Permian Basin, which underlies an area of southeast New Mexico and west Texas approximately 250 miles wide and 300 miles long. Commercial accumulations of hydrocarbons occur in multiple stratigraphic horizons, at depths ranging from less than 1,000 feet to over 25,000 feet. At December 31, 2017, substantially all of our 840 MMBoe total estimated proved reserves were located in our core operating areas and consisted of approximately 60 percent oil and 40 percent natural gas. We have assembled a multi-year inventory of horizontal development and exploration projects across our four core operating areas.

The following table sets forth information with respect to drilling of wells commenced during the periods indicated:

	Years Ended December 31, 2017	2016	2015
Gross wells	311	249	361
Net wells	197	170	228
Percent of gross wells drilled horizontally	100%	100%	86%
Percent of gross wells:			
Producers	61%	56%	74%
Unsuccessful	1%	-	1%
Awaiting completion at year-end	38%	44%	25%
	100%	100%	100%

Summary of Core Operating Areas

The following is a summary of information regarding our core operating areas:

	December 31, 2017					
Core Operating Areas	Estimated Proved Reserves (MMBoe)	% Oil	% Proved Developed	Total Gross Acreage (in thousands)	Total Net Acreage (in thousands)	2017 Average Daily Production (MBoe per Day)
Northern Delaware Basin	295	50%	68%	373	259	90
Southern Delaware Basin	127	72%	62%	146	94	27
Midland Basin	266	66%	67%	265	154	45
New Mexico	152	56%	87%	121	78	31

Shelf						
Total	840	60%	70%	905	585	193

Core operating areas

Northern Delaware Basin. At December 31, 2017, we had estimated proved reserves in this area of 295 MMBoe, representing 35 percent of our total proved reserves.

The Northern Delaware Basin is characterized by a thick, resource-rich hydrocarbon column that lends itself to multi-zone development. We leverage leading-edge horizontal drilling and completion technologies, utilizing multi-well pad sites to develop multiple producing formations. Our activity has targeted the Avalon shale and Bone Spring and Wolfcamp formations at depths from 6,500 to 13,500 feet. We continue to test and develop additional landing intervals within these formations.

During the year ended December 31, 2017, we commenced drilling or participated in the drilling of 149 (78 net) wells in this area. Throughout 2017, we completed 126 (66 net) wells that are producing. Additionally in 2017, we abandoned 1 (1 net) well that was spud in 2014 and used to monitor offsetting well stimulations. During 2017, we continued (i) development and step-out activity targeting the Avalon shale, Bone Spring sands and Wolfcamp formation and (ii) to refine our completion techniques. During 2017, all of the wells we commenced or participated in drilling were drilled horizontally.

Southern Delaware Basin. At December 31, 2017, we had estimated proved reserves in this area of 128 MMBoe, representing 15 percent of our total proved reserves.

Across our Southern Delaware Basin acreage position, we primarily target the Bone Spring and Wolfcamp formations, which generally range from 8,000 to 12,500 feet in depth. We leverage leading-edge horizontal drilling and completion technologies, utilizing multi-well pad sites and extended lateral lengths, to develop these producing formations.

During the year ended December 31, 2017, we commenced drilling or participated in the drilling of 61 (38 net) wells in this area. Throughout 2017, we completed 53 (33 net) wells that are producing. Additionally in 2017, we spud 2 (2 net) wells that were subsequently abandoned due to mechanical issues. During 2017, we continued (i) development and step-out activity targeting the Bone Spring sands and Wolfcamp shale and (ii) evaluation of our enhanced stimulation procedures of certain horizontal wells. During 2017, all of the wells we commenced or participated in drilling were drilled horizontally.

Midland Basin. At December 31, 2017, we had estimated proved reserves in this area of 266 MMBoe, representing 32 percent of our total proved reserves.

Our primary objectives in the Midland Basin area are the Spraberry and Wolfcamp formations, which are typically encountered at depths of 7,500 feet to 11,500 feet. On our Midland Basin assets, we are developing these formations with horizontal drilling, utilizing multi-well pad sites and extended lateral development. We are also continuing to optimize well spacing, landing intervals and completion techniques.

During the year ended December 31, 2017, we commenced drilling or participated in the drilling of 58 (47 net) wells in this area. Throughout 2017, we completed 78 (49 net) wells that are producing. Additionally in 2017, we spud 1 (1 net) well that was subsequently abandoned due to mechanical issues. During 2017, all of the wells we commenced or participated in drilling were drilled horizontally.

New Mexico Shelf. At December 31, 2017, we had estimated proved reserves in this area of 151 MMBoe, representing 18 percent of our total proved reserves.

Within this area our primary objectives are the Yeso, San Andres and Grayburg formations, with producing depths ranging from approximately 900 feet to 7,500 feet. During 2017, we continued our horizontal drilling of the Yeso formation.

During the year ended December 31, 2017, we commenced drilling or participated in the drilling of 43 (34 net) wells in this area. Throughout 2017, we completed 48 (39 net) wells that are producing. During 2017, all of the wells we commenced or participated in drilling were drilled horizontally.

Drilling Activities

The following table sets forth information with respect to (i) wells drilled and completed during the periods indicated and (ii) wells drilled in a prior period but completed in the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

	Years Ended December 31,					
	2017		2016		2015	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development wells:						
Productive	96	76	95	76	180	116
Dry	1	1	-	-	1	1
Exploratory wells:						
Productive	209	112	131	83	260	154
Dry	3	3	1	1	3	2
Total wells:						
Productive	305	188	226	159	440	270
Dry (a)	4	4	1	1	4	3
Total	309	192	227	160	444	273

(a) The dry hole category includes 4 (4 net) wells that were unsuccessful due to mechanical or other issues for the year ended December 31, 2017.

Present activities. The following table sets forth information about wells for which drilling was in-progress or are pending completion at December 31, 2017, which are not included in the above table:

	Drilling In-Progress		Pending Completion	
	Gross	**Net**	**Gross**	**Net**
Development and exploratory wells	35	22	85	49

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Our Production, Prices and Expenses

The following table sets forth summary information concerning our production and operating data for the years ended December 31, 2017, 2016 and 2015. The actual historical data in this table excludes results from our acquisition of certain assets of Reliance Energy, Inc. (the “Reliance Acquisition”) for periods prior to October 2016. Because of normal production declines, increased or decreased drilling activities, fluctuations in commodity prices and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Years Ended December 31,		
	2017	**2016**	**2015**
Production and operating data:			
Net production volumes:			
Oil (MBbl)	43,472	33,840	34,457
Natural gas (MMcf)	161,089	127,481	106,987
Total (MBoe)	70,320	55,087	52,288
Average daily production volumes:			
Oil (Bbl)	119,101	92,459	94,403
Natural gas (Mcf)	441,340	348,309	293,115
Total (Boe)	192,658	150,511	143,256
Average prices per unit:			
Oil, without derivatives (Bbl)	$ 48.13	$ 39.90	$ 44.69
Oil, with derivatives (Bbl) (a)	$ 49.93	$ 57.90	$ 62.03
Natural gas, without derivatives (Mcf)	$ 3.07	$ 2.23	$ 2.46
Natural gas, with derivatives (Mcf) (a)	$ 3.06	$ 2.36	$ 2.80
Total, without derivatives (Boe)	$ 36.78	$ 29.68	$ 34.49
Total, with derivatives (Boe) (a)	$ 37.88	$ 41.03	$ 46.60
Operating costs and expenses per Boe: (b)			
Oil and natural gas production	$ 5.80	$ 5.81	$ 7.46
Production and ad valorem taxes	$ 2.82	$ 2.38	$ 2.90
Depreciation, depletion and amortization	$ 16.29	$ 21.19	$ 23.40
General and administrative	$ 3.46	$ 4.09	$ 4.42

(a) Includes the effect of net cash receipts from derivatives:

	Years Ended December 31,		
(in millions)	**2017**	**2016**	**2015**
Net cash receipts from derivatives:			
Oil derivatives	$ 79	$ 609	$ 597
Natural gas derivatives	-	16	36
Total	$ 79	$ 625	$ 633

The presentation of average prices with derivatives is a result of including the net cash receipts from commodity derivatives that are presented in our statements of cash flows. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

(b) Per Boe amounts calculated using dollars and volumes rounded to thousands.

Productive Wells

The following table sets forth the number of productive oil and natural gas wells on our properties at December 31, 2017, 2016 and 2015. This table does not include wells in which we own a royalty interest only.

	Gross Productive Wells			Net Productive Wells		
	Oil	**Natural Gas**	**Total**	**Oil**	**Natural Gas**	**Total**
December 31, 2017						
Core Operating Areas:						
Northern Delaware Basin	1,282	439	1,721	726	213	939
Southern Delaware Basin	319	26	345	195	17	212
Midland Basin	2,747	15	2,762	1,675	6	1,681
New Mexico Shelf	3,200	121	3,321	2,548	44	2,592
Other	-	3	3	-	-	-
Total	7,548	604	8,152	5,144	280	5,424
December 31, 2016						
Core Operating Areas:						
Northern Delaware Basin	1,164	454	1,618	662	212	874
Southern Delaware Basin	270	27	297	163	17	180
Midland Basin	2,577	15	2,592	1,298	5	1,303
New Mexico Shelf	3,222	126	3,348	2,560	33	2,593
Other	-	3	3	-	-	-
Total	7,233	625	7,858	4,683	267	4,950
December 31, 2015						
Core Operating Areas:						
Northern Delaware Basin	1,141	460	1,601	651	217	868
Southern Delaware Basin	222	53	275	138	29	167
Midland Basin	2,476	24	2,500	1,173	8	1,181
New Mexico Shelf	3,143	114	3,257	2,531	42	2,573
Other	-	3	3	-	0	0
Total	6,982	654	7,636	4,493	296	4,789

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Marketing Arrangements

General. We market our oil and natural gas in accordance with standard energy industry practices. The marketing effort endeavors to obtain the combined highest netback and most secure market available at that time. In addition, marketing supports our operations group as it relates to the planning and preparation of future development activity so that available markets can be assessed and secured. This planning also involves the coordination of access to the physical facilities necessary to connect forthcoming wells as efficiently as possible.

Oil. We generally do not transport, refine or process the oil we produce. The majority of our oil in southeast New Mexico is connected directly to oil gathering pipelines. Most of our gathered oil from the New Mexico Shelf is utilized in a two-refinery complex in southeast New Mexico. Most of our oil production from the New Mexico portion of our Northern Delaware Basin core area is now connected to the Alpha Crude Connector, LLC (“ACC”) pipeline system. Most of the oil production connected to the ACC pipeline system is purchased by three different purchasers and moved on several different pipeline outlets connected to ACC. We have assigned our shipping rights on ACC to these purchasers and they purchase our production at the receipt points that are connected at our lease tank batteries into ACC. The remaining oil in our Northern Delaware Basin core area is purchased by approximately five different oil purchasers and trucked to regional pipeline stations.

Most of our oil in the Southern Delaware Basin is on one of three different oil gathering systems. One of these systems is a crude oil gathering and transportation system operated by a subsidiary of Oryx Southern Delaware Holdings, LLC (“Oryx”), an entity in which we own a 23.75 percent membership interest. The oil is then transported to the Crane/Midland/Colorado City pipeline corridor and then onto Cushing or Gulf Coast markets. A significant portion of our Midland Basin production is on one of six different gathering systems. Most of this production is sweet crude and is transported by third parties to Cushing or Gulf Coast markets. The balance of our oil in these areas that is not directly connected to pipelines is trucked to unloading stations on those same pipelines. We sell the majority of the oil we produce under contracts using market-based pricing. This price is then adjusted for differentials based upon delivery location and oil quality.

Natural Gas. We consider all natural gas gathering, treating and processing service providers in the areas of our production and evaluate market options to obtain the best price reasonably available given the necessary operating conditions. We sell the majority of our natural gas under individually negotiated natural gas purchase contracts using market-based pricing. The majority of our natural gas is subject to long-term agreements that generally extend five to ten years from the effective date of the subject contract.

The majority of our natural gas is casinghead gas, which is sold at the lease location under (i) percentage of proceeds processing contracts, (ii) fee-based contracts or (iii) a hybrid of percentage of proceeds and fee-based contracts. The purchaser gathers our casinghead natural gas in the field where it is produced and transports it via pipeline to natural gas processing plants where natural gas liquid products are extracted and sold by the processors. The portion of natural gas remaining after liquid extraction is residue gas, which is placed on residue pipeline systems downstream of the subject processing plant. Under our percentage of proceeds and hybrid percentage of proceeds and fee-based contracts, we receive a percentage of the value for the extracted liquids and the residue gas. Under our fee-based contracts, we receive natural gas liquids and residue gas value, less the fee component thereof, or are invoiced the fee component of our service.

Our Principal Customers

We sell our oil and natural gas production principally to marketers and other purchasers that have access to pipeline facilities. In areas where there is no practical access to pipelines, oil is transported to storage facilities by trucks owned or otherwise arranged by the marketers or purchasers. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted.

For 2017, revenues from oil and natural gas sales to Plains Marketing and Transportation, Inc. and Holly Frontier Refining and Marketing, LLC accounted for approximately 21 percent and 10 percent, respectively, of our total operating revenues. While the loss of either of these purchasers may result in a temporary interruption in sales of, or a lower price for, our production, we believe that the loss of either of these purchasers would not have a material adverse effect on our operations, as there are alternative purchasers in our producing regions. See Note 12 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.”

Competition

The oil and natural gas industry in the areas in which we operate is highly competitive. We encounter strong competition from numerous parties, ranging generally from small independent producers to major integrated companies. We primarily encounter significant competition in acquiring properties. At higher commodity prices, we also face competition in contracting for drilling, pressure pumping and workover equipment and securing trained personnel. Many of these competitors have financial, technical and personnel resources substantially larger than ours. As a result, our competitors may be able to pay more for desirable properties, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit.

In addition to competition for drilling, pressure pumping and workover equipment, we are also affected by the availability of related equipment and materials. The oil and natural gas industry periodically experiences shortages of drilling and workover rigs, equipment, pipe, materials and personnel, which can delay drilling, workover and exploration activities and cause significant price increases. We are unable to predict the timing or duration of any such shortages.

Working Capital

Based on current market conditions, we have maintained a stable liquidity position. Our principal source of liquidity is available borrowing capacity under our credit facility. At December 31, 2017, we had $322 million of debt outstanding under our credit facility and $1.7 billion of unused commitments under our credit facility. Subsequent to December 31, 2017, our cash position increased by approximately $250 million as a result of completing two divestitures of oil and natural gas properties located in the Southern Delaware Basin core area. Our primary needs for cash are development, exploration and acquisitions of oil and natural gas assets, payment of contractual obligations and working capital obligations. However, additional borrowings under our credit facility or the issuance of additional debt securities will require a greater portion of our cash flow from operations to be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions.

Applicable Laws and Regulations

Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and the plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental, Health and Safety Matters

General. Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws, rules and regulations may, among other things:

- require the acquisition of various permits before drilling commences;

- require notice to stakeholders of proposed and ongoing operations;

- require the installation of expensive pollution control equipment;

- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling and production and saltwater disposal activities;

- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, or otherwise restrict or prohibit activities that could impact the environment, including water resources; and

- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules and regulations may also restrict the production rate of oil and natural gas below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Violations and liabilities with respect to these laws and regulations could result in significant administrative, civil or criminal penalties, remedial clean-ups, natural resource damages, permit modifications or revocations, operational interruptions or shutdowns and other liabilities. The costs of remedying such conditions may be significant, and remediation obligations could adversely affect our financial condition, results of operations and leasehold acreage. Additionally, environmental laws and regulations are revised frequently, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules and regulations to which our business is subject.

Waste handling. The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Pursuant to regulatory guidance issued by the federal Environmental Protection Agency (the "EPA"), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and certain environmental organizations entered into a consent decree to address EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and natural gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes or to sign a determination that revision of the regulations is not necessary. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response Compensation and Liability Act ("CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current or former owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Each state, including Texas, also has environmental cleanup laws analogous to CERCLA.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose storage, treatment and disposal of hazardous substances, wastes or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial operations to prevent future contamination.

Water discharges. The federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters, including dredge and fill activities in regulated wetlands, is prohibited, except in accordance with the terms of a permit issued by the EPA, or, in some circumstances, the U.S. Army Corps of Engineers (the "Corps"), or an analogous state agency. In addition, spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. Further, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

In September 2015, new EPA and U.S. Army Corps of Engineers rules to revise the definition of "waters of the United States" ("WOTUS") for all Clean Water Act programs, thereby defining the scope of the EPA's and the Corps' jurisdiction, became effective. To the extent the rule expands the scope of jurisdiction of the Clean Water Act, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. The rule has been challenged in court on the grounds that it unlawfully expands the reach of Clean Water Act programs, and implementation of the rule has been stayed pending resolution of the court challenge. In response to this decision, the EPA and the Corps resumed nationwide use of the agencies' prior regulations defining the term "waters of the United States." Those regulations will be implemented as they were prior to the effective date of the new WOTUS rule. In January 2017, the U.S. Supreme Court accepted review of the WOTUS rule to determine whether jurisdiction to hear challenges to the rule rests with the federal district or appellate courts. In February 2017, the new Presidential administration issued an Executive Order directing the EPA and the Corps to review and, consistent with applicable law, to initiate a rule-making to rescind or revise the WOTUS rule. The EPA and the Corps published a notice of intent to review and rescind or revise the rule in March 2017. In addition, the U.S. Department of Justice filed a motion with the U.S. Supreme Court in March 2017 requesting that the U.S. Supreme Court stay the suit concerning which court should hear challenges to the rule. The U.S. Supreme Court denied the motion in April 2017. In June 2017, the EPA and the U.S. Army Corps proposed a rule that would initiate the first step in a two-step process intended to review and revise the definition of "waters of the United States" consistent with President Trump's Executive Order. Under the proposal, the first step would be to rescind the May 2015 final rule and put back into effect the narrower language defining "waters of the United States" under the Clean Water Act that existed prior to the rule. The second step would be a notice-and-comment rule-making in which the agencies will conduct a substantive reevaluation of the definition of "waters of the United States." Finally, in January 2018, the Supreme Court ruled that the WOTUS rule must first be reviewed in federal district courts, remanding the case at issue to the district level and putting the status of the Sixth Circuit's stay of the new rule into question. Citing uncertainty caused by litigation, the EPA subsequently announced a two year stay of the application of the rule as it undertakes its own review of the rule.

Safe Drinking Water Act. Our oil and natural gas exploration and production operations generate produced water, drilling muds, and other waste streams, some of which may be disposed via injection in underground wells situated in non-producing subsurface formations. The drilling and operation of these injection wells are regulated by the federal Safe Drinking Water Act (the "SDWA"). The Underground Injection Well Program under the SDWA requires that we obtain permits from the EPA or delegated state agencies for our disposal wells, establishes minimum standards for injection well operations, restricts the types and quantities of fluids that may be injected and prohibits the migration of fluid containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, imposition of fines and penalties from governmental agencies, incurrence of expenditures for remediation of affected resources, and imposition of liability by landowners or other parties claiming damages for alternative water supplies, property damages, and personal injuries. Any changes in the laws or regulations or the inability to obtain permits for new injection wells in the future may affect our ability to dispose of produced waters and would ultimately increase the cost of our operations, which costs could be significant. For example, in 2014 the Railroad Commission of Texas (the "RRC") adopted additional permit rules for injection wells to address seismic activity concerns within the state. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells, and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. Furthermore, in response to recent seismic events near underground injection wells used for the disposal of oil and natural gas-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such injection wells. For example, in 2016, the Oklahoma Corporation Commission issued various orders and regulations applicable to disposal operations in specific counties in Oklahoma. These rules require that disposal well operators, among other things, conduct additional mechanical integrity testing, make sure that their wells are not injecting wastes into targeted formations, and/or reduce the volumes of wastes disposed in such wells. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase, and our ability to continue production may be delayed or limited, which could have a material adverse effect on our results of operations and financial position.

Air emissions. The federal Clean Air Act (the "CAA"), and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. These and other laws and regulations may increase the costs of compliance for some facilities where we operate. Obtaining or renewing permits also has the potential to delay the development of our projects. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources.

For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard ("NAAQS") for ozone from 75 to 70 parts per billion. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. In addition, in June 2016, the EPA finalized rules under the CAA regarding criteria for aggregating multiple sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities (such as tank batteries), on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install costly pollution control equipment. In a separate rulemaking in June 2016, the EPA finalized new air emission control requirements for emissions of methane from certain equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. The final rule package includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions, and also imposes leak detection and repair requirements on operators. In addition, the rule package extends existing volatile organic compound (“VOC”) standards under the EPA’s Subpart OOOO of the New Source Performance Standards to include previously unregulated equipment within the oil and natural gas source category. However, in June 2017, the EPA proposed a two year stay of the fugitive emissions monitoring requirements, pneumatic pump standards, and closed vent system certification requirements in the 2016 New Source Performance Standards rule for the oil and gas industry while it reconsiders these aspects of the rule. The proposal is still under consideration. The U.S. Bureau of Land Management (“BLM”) finalized similar rules in November 2016 that limit methane emissions from new and existing oil and natural gas operations on federal lands through limitations on the venting and flaring of gas, as well as enhanced leak detection and repair requirements. The BLM adopted final rules in January 2017. Operators generally had one year from the January 2017 effective date to come into compliance with the rule’s requirements. However, in December 2017, the BLM temporarily suspended or delayed certain of these requirements set forth in its Venting and Flaring Rule until January 2019, pending administrative review of the rule. These air emission rules have the potential to increase our compliance costs.

Climate change. In response to findings that emissions of carbon dioxide, methane and other “greenhouse gases” (“GHGs”) present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of GHGs under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis, including GHG emissions resulting from the completion and workover operations of hydraulically fractured oil wells. Recent federal regulatory action with respect to climate change has focused on methane emissions. As noted above, both the EPA and the BLM finalized rules in 2016 that limit methane emissions from upstream oil and natural gas exploration and production operations. Increased regulation of methane and other GHGs have the potential to result in increased compliance costs and, consequently, adversely affect our operations.

On August 3, 2015, the EPA also issued new regulations limiting carbon dioxide emissions from existing power generation facilities. Under this rule, nationwide carbon dioxide emissions would be reduced by approximately 30 percent from 2005 levels by 2030 with a flexible interim goal. Several industry groups and states challenged the rule. On February 9, 2016, the

U.S. Supreme Court stayed the implementation of this rule pending judicial review. On March 28, 2017, President Trump signed an Executive Order directing the EPA to review the regulations, and on April 4, 2017, the EPA announced that it was reviewing the 2015 carbon dioxide regulations. On April 28, 2017, the U.S. Court of Appeals for the District of Columbia stayed the litigation pending the current administration's review. That stay was extended for another 60 days on August 8, 2017. On October 10, 2017, the EPA initiated the formal rulemaking process to repeal the regulations. The EPA's proposal will be subject to public comment and likely legal challenge, and as such, we cannot predict at this time what impact the rulemaking will have on the demand for oil and natural gas production and our operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of Congressional action, many states have established GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. In addition, in 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement requires countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. However, in June 2017, President Trump announced that the United States plans to withdraw from the Paris Agreement and seek negotiations either to reenter the Paris Agreement on different terms or establish a new framework agreement. The Paris Agreement provides for a four-year exit process beginning in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Reduced demand for the oil and natural gas that we produce could also have the effect of lowering the value of our reserves. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. It should also be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits brought by public and private entities against oil and gas companies in connection with their greenhouse gas emissions. Should we be targeted by any such litigation, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Hydraulic fracturing*.* Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing as part of our operations. The process is typically regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel and issued guidance in February 2014 governing such activities. The EPA has also issued final regulations under the CAA establishing performance standards, including standards for the capture of VOCs and methane released during hydraulic fracturing (although the EPA has temporarily suspended or delayed compliance with certain of these standards as they undergo an administrative review); an advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; and final rules in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, New Mexico and Texas have adopted hydraulic fracturing fluid disclosure requirements, and the RRC has also adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. In addition, local governments have also taken steps to regulate hydraulic fracturing, including imposing restrictions or moratoria on oil and natural gas activities occurring within their boundaries. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under some circumstances, noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, this years-long study report does not appear to provide any basis for further regulation of hydraulic fracturing at the federal level.

We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our well control, general liability and excess liability insurance policies may cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies. If new laws or regulations significantly restrict hydraulic fracturing activities or impose burdens on new permitting or operating requirements, our ability to utilize hydraulic fracturing may be curtailed, and this may in turn reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Operations on Federal Lands. We currently operate on federal lands under the jurisdiction of the BLM. Permitting for oil and natural gas activities on federal lands can take significantly longer than the state permitting process. Delays in obtaining permits necessary can disrupt our operations and have an adverse effect on our business. As noted above, in November 2016, the BLM finalized rules that restrict methane emissions from oil and natural gas activities on federal lands by limiting venting and flaring of natural gas from wells and other equipment. The final rule also requires operators to pay royalties to the BLM on flared gas from wells already connected to gas capture infrastructure, and allows the agency to set royalty rates at or above 12.5 percent of the value of production. These rules could result in increased compliance costs for our operations, which in turn could have an adverse effect on our business and results of operations.

Endangered species*.* The federal Endangered Species Act (the “ESA”) and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of our drilling operations are conducted in areas where protected species are known to exist. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting drilling operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we perform drilling activities could impair our ability to timely complete drilling and developmental operations and could adversely affect our future production from those areas. The designation of previously unprotected species as threatened or endangered in areas where we or our oil and natural gas exploration and production customers operate could cause us or our customers to incur increased costs arising from species protection measures and could result in delays or limitations in our customers’ performance of operations, which could reduce demand for our midstream services.

***National Environmental Policy Act**.* Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay or even halt development of some of our oil and natural gas projects.

***OSHA and other laws and regulations**.* We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety.

We are not aware of any existing environmental issues, claims or regulations that will require us to incur material capital expenditures during 2018, and we did not incur material capital expenditures relating to environmental issues, claims or regulations during 2017. However, we cannot assure that the passage or application of more stringent laws or regulations or the application of existing laws in the future will not require us to incur material capital expenditures or have a material adverse effect on our financial position or results of operations.

Our Employees

Our corporate headquarters are located at One Concho Center, 600 West Illinois Avenue, Midland, Texas 79701. We also maintain various field offices in Texas and New Mexico. At December 31, 2017, we had 1,203 employees, 457 of whom were employed in field operations. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be good. We also utilize the services of contractors to perform various field and other services.

Available Information

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the U.S. Securities and Exchange Commission (the “SEC”) under the Exchange Act. The public may read and copy any materials that we file or furnish with the SEC at the SEC’s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file or furnish electronically with the SEC. The public can obtain any documents that we file with the SEC at *www.sec.gov*.

We also make available free of charge through our website, *www.concho.com*, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Non-GAAP Financial Measures and Reconciliations

Reconciliation of Standardized Measure to PV-10

PV-10 is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas assets. PV-10, however, is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of the GAAP standardized measure of discounted future net cash flows to PV-10 (non-GAAP) at December 31, 2017, 2016 and 2015:

	December 31,		
(in millions)	**2017**	**2016**	**2015**
Standardized measure of discounted future net cash flows	$ 7,478	$ 4,190	$ 3,739
Present value of future income taxes discounted at 10%	1,001	652	524
PV-10	$ 8,479	$ 4,842	$ 4,263

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Reconciliation of Net Income (Loss) to EBITDAX

EBITDAX (as defined below) is presented herein and reconciled from the GAAP measure of net income (loss) because of its wide acceptance by the investment community as a financial indicator.

We define EBITDAX as net income (loss), plus (1) exploration and abandonments, (2) depreciation, depletion and amortization, (3) accretion of discount on asset retirement obligations, (4) impairments of long-lived assets, (5) non-cash stock-based compensation, (6) (gain) loss on derivatives, (7) net cash receipts from (payments on) derivatives, (8) (gain) loss on disposition of assets, net, (9) interest expense, (10) loss on extinguishment of debt, (11) federal and state income tax expense (benefit) from continuing operations and (12) similar items listed above that are presented in discontinued operations. EBITDAX is not a measure of net income (loss) or cash flows as determined by GAAP.

Our EBITDAX measure provides additional information that may be used to better understand our operations. EBITDAX is one of several metrics that we use as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to, or more meaningful than, net income (loss) as an indicator of operating performance. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. EBITDAX, as used by us, may not be comparable to similarly titled measures reported by other companies. We believe that EBITDAX is a widely followed measure of operating performance and is one of many metrics used by our management team and by other users of our consolidated financial statements. For example, EBITDAX can be used to assess our operating performance and return on capital in comparison to other independent exploration and production companies without regard to financial or capital structure and to assess the financial performance of our assets and our company without regard to capital structure or historical cost basis.

The following table provides a reconciliation of the GAAP measure of net income (loss) to EBITDAX (non-GAAP) for the periods indicated:

	Years Ended December 31,				
(in millions)	**2017**	**2016**	**2015**	**2014**	**2013**
Net income (loss)	$ 956	$ (1,462)	$ 66	$ 538	$ 251
Exploration and abandonments	59	77	59	285	109
Depreciation, depletion and amortization	1,146	1,167	1,223	980	773
	8	7	8	7	6

Accretion of discount on asset retirement obligations										
Impairments of long-lived assets		-		1,525		61		447		65
Non-cash stock-based compensation		60		59		63		47		35
(Gain) loss on derivatives		126		369		(700)		(891)		124
Net cash receipts from (payments on) derivatives		79		625		633		72		(32)
(Gain) loss on disposition of assets, net		(678)		(118)		54		9		1
Interest expense		146		204		215		217		219
Loss on extinguishment of debt		66		56		-		4		29
Income tax expense (benefit) from continuing operations		(75)		(876)		31		318		118
Discontinued operations		-		-		-		-		(12)
EBITDAX	$	1,893	$	1,633	$	1,713	$	2,033	$	1,686

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Item 1A. Risk Factors

You should consider carefully the following risk factors together with all of the other information included in this report and other reports filed with the SEC before investing in our securities. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our securities could decline and you could lose all or part of your investment.

Risks Related to Our Business

Oil, natural gas and natural gas liquid prices are volatile. A decline in oil, natural gas and natural gas liquid prices could adversely affect our financial position, financial results, cash flow, access to capital and ability to grow.

Our future financial condition, revenues, results of operations, rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production and the prices prevailing from time to time for oil, natural gas and natural gas liquids. Oil, natural gas and natural gas liquid prices historically have been volatile, and are likely to continue to be volatile in the future, especially given current geopolitical conditions. This price volatility also affects the amount of cash flow we have available for capital expenditures and our ability to borrow money or raise additional capital. The prices and levels of production for oil, natural gas and natural gas liquids are subject to a variety of factors beyond our control, including:

- the overall global demand for oil, natural gas and natural gas liquids;

- the domestic and foreign supply of oil, natural gas and natural gas liquids;

- the overall North American oil, natural gas and natural gas liquids supply and demand fundamentals, including:

    - the U.S. economy,

- weather conditions, and
- liquefied natural gas deliveries to and exports from the United States;
- economic conditions worldwide;
- the level of global inventories;
- political and economic developments in oil and natural gas producing regions, including Africa, South America and the Middle East;
- the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to influence global oil supply levels;
- technological advances affecting energy consumption and energy supply;
- the effect of energy conservation efforts;
- political and economic events that directly or indirectly impact the relative strength or weakness of the U.S. dollar, on which oil prices are benchmarked globally, against foreign currencies;
- domestic and foreign governmental regulations, including limits on the United States' ability to export crude oil, and taxation;
- the cost and availability of products and personnel needed for us to produce oil and natural gas, including rigs, crews, sand, water and water disposal;

- risks related to the concentration of our operations in the Permian Basin of southeast New Mexico and west Texas and the level of commodity inventory in the Permian Basin;

- the proximity, capacity, cost and availability of pipelines and other transportation facilities, as well as the availability of commodity processing and gathering and refining capacity;

- the quality of the oil we produce; and

- the price and availability of alternative fuels.

Furthermore, oil and natural gas prices continued to be volatile in 2017. For example, the NYMEX oil prices in 2017 ranged from a high of $60.42 to a low of $42.53 per Bbl and the NYMEX natural gas prices in 2017 ranged from a high of $3.72 to a low of $2.56 per MMBtu. Further, the NYMEX oil prices and NYMEX natural gas prices reached highs of $66.14 per Bbl and $3.63 per MMBtu, respectively, during the period from January 1, 2018 to February 16, 2018.

Declines in oil, natural gas and natural gas liquid prices would not only reduce our revenue, but could also reduce the amount of oil and natural gas that we can produce economically. This in turn would lower the amount of oil and natural gas reserves we could recognize and, as a result, could have a material adverse effect on our financial condition and results of operations. If the oil and natural gas industry experiences significant price declines for a sustained period, such as those experienced in 2015 to 2017, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future indebtedness or obtain additional capital on attractive terms, all of which can adversely affect the value of our securities.

Approximately 30 percent of our total estimated proved reserves at December 31, 2017 were undeveloped, and those reserves may not ultimately be developed.

At December 31, 2017, approximately 30 percent of our total estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. Our reserves data assumes that we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove correct. Our reserve report at December 31, 2017 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $2.3 billion. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to write-off these reserves. In addition, under the SEC’s reserve rules, because proved undeveloped reserves may be recognized only if they relate to wells planned to be drilled within five years of the date of their initial recognition, we may be required to write-off any proved undeveloped reserves that are not developed within this five-year timeframe. For example, as of December 31, 2017, we wrote-off approximately 61 MMBoe of proved undeveloped reserves because they are no longer expected to be developed within five years of the date of their initial recognition.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could cause our costs to increase or production volumes to decrease, which would reduce our cash flows.

Our future financial condition and results of operations depend on the success of our exploration and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economical than forecasted. Further, many factors may curtail, delay or cancel drilling, including the following:

- shortages of or delays in obtaining equipment and qualified personnel or in obtaining sand or water for hydraulic fracturing activities;

- delays imposed by or resulting from compliance with regulatory and contractual requirements;

- reductions in oil, natural gas and natural gas liquid prices;

- pressure or irregularities in geological formations;

- equipment failures or accidents;

- adverse weather conditions;

- political events, public protests, civil disturbances, terrorist acts or cyber attacks;

- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;

- surface access restrictions;

- failure to obtain regulatory and third-party approvals;
- actions by third-party operators of our properties;

- loss of title or other title related issues;

- delays and costs of drilling wells on lands subject to complex development terms and circumstances;

- oil, natural gas liquids or natural gas gathering, transportation and processing availability restrictions or limitations;

- limitations in the market for oil, natural gas and natural gas liquids; and

- limited availability of financing at acceptable terms.

In addition, the results of our exploratory drilling in new or emerging plays are more uncertain than drilling results in areas that are developed and have established production. Since new or emerging plays and new formations have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

Multi-well pad drilling and project development may result in volatility in our operating results.

We utilize multi-well pad drilling and project development where practical. Project development may involve more than one multi-well pad being drilled and completed at one time in a relatively confined area. Wells drilled on a pad or in a project may not be brought into production until all wells on the pad or project are drilled and completed. Problems affecting one pad or a single well could adversely affect production from all of the wells on the pad or in the entire project. As a result, multi-well pad drilling and project development can cause delays in the scheduled commencement of production, or interruptions in ongoing production. These delays or interruptions may cause declines or volatility in our operating results due to timing as well as declines in oil and natural gas prices. Further, any delay, reduction or curtailment of our development and producing operations, due to operational delays caused by multi-well pad drilling or project development, or otherwise, could result in the loss of acreage through lease expirations.

Additionally, infrastructure expansion, including more complex facilities and takeaway capacity, could become challenging in project development areas. Managing capital expenditures for infrastructure expansion could cause economic constraints when considering design capacity.

Prolonged decreases in our drilling program may require us to pay certain non-use fees or impact our ability to comply with certain contractual requirements.

Oil prices declined substantially during the second half of 2014 and continued to decline through 2016, but began to recover in 2017. In the event that oil prices declined for a sustained period, we may experience significant decreases in drilling activity. Due to the nature of our drilling programs and the oil and natural gas industry in general, we are a party to certain agreements that require us to meet various contractual obligations or require us to utilize a certain amount of goods or services, including, but not limited to, water commitments, throughput volume commitments, power commitments and drilling commitments. In the event that oil and natural gas prices decrease, and as a result continue to reduce the demand for drilling and production, this could lead to a decrease in our drilling activity and production levels, which could, in turn, require us to pay for unutilized goods or services or impact our ability to meet these contractual obligations.

We may incur losses as a result of title defects in our oil and natural gas properties.

It is our practice to initially conduct only a cursory title review of the oil and natural gas properties on which we do not have proved reserves. To the extent title opinions or other investigations prior to our commencement of drilling operations reflect defects affecting such properties, we are typically responsible for curing any such defects at our expense. Additionally, the discovery of any such defects could delay or prohibit the commencement of drilling operations on the affected properties. These impacts and other potential losses resulting from title defects in our oil and natural gas properties could have a material adverse effect on our business, financial condition and results of operations.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners and other sources for use in our operations. Over the past few years, extreme drought conditions persisted in west Texas and southeast New Mexico. Although conditions have improved, we cannot guarantee what conditions may occur in the future. Severe drought conditions can result in local water districts taking steps to restrict the use of water subject to their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs and additional operating restrictions or delays and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. We routinely utilize hydraulic fracturing techniques in many of our drilling and completion programs. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the SDWA's Underground Injection Control Program and issued guidance in February 2014, governing such activities. The EPA has also issued: final regulations under the CAA establishing performance standards, including standards for the capture of VOCs and methane released during hydraulic fracturing (although the EPA has temporarily suspended or delayed compliance with certain of these standards as they undergo an administrative review); an advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; and final rules in June 2016 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, New Mexico and Texas have adopted hydraulic fracturing fluid disclosure requirements, and the RRC has also adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. In addition, local governments have also taken steps to regulate hydraulic fracturing, including imposing restrictions or moratoria on oil and gas activities occurring within their boundaries. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under some circumstances, noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, this years-long study report does not appear to provide any basis for further regulation of hydraulic fracturing at the federal level.

If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements and could also result in permitting delays and potential cost increases. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Climate change legislation, regulations restricting emissions of "greenhouse gases" or legal or other action taken by public or private entities related to climate change could result in increased operating costs and reduced demand for the crude oil and natural gas that we produce.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of GHGs under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis, including GHG emissions resulting from the completion and workover operations of hydraulically fractured oil wells. Recent federal regulatory action with respect to climate change has focused on methane emissions. For example, in June 2016, the EPA finalized new air emission controls for emissions of methane from certain equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. The final rule package includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions, and also imposes leak detection and repair requirements on operators. The BLM finalized similar rules in November 2016 that limit methane emissions from new and existing oil and gas operations on federal lands through limitations on the venting and flaring of gas, as well as enhanced leak detection and repair requirements. The BLM adopted the final rules in January 2017. Operators generally had one year from the January 2017 effective date to come into compliance with the rule's requirements. However, in December 2017, the BLM temporarily suspended or delayed certain of these requirements set forth in its Venting and Flaring Rule until January 2019, pending administrative review of the rule. These methane emission rules have the potential to increase our compliance costs.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of Congressional action, many states have established GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Reduced demand for the oil and gas that we produce could also have the effect of lowering the value of our reserves. It should also be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits brought by public and private entities against oil and gas companies in connection with their GHG emissions. Should we be targeted by any such litigation, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to the causation of or contribution to the asserted damage, or to other mitigating factors.

Estimates of proved reserves and future net cash flows are not precise. The actual quantities of our proved reserves and our future net cash flows may prove to be lower than estimated.

Numerous uncertainties exist in estimating quantities of proved reserves and future net cash flows therefrom. Our estimates of proved reserves and related future net cash flows are based on various assumptions, which may ultimately prove to be inaccurate.

Petroleum engineering is a subjective process of estimating accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations by governmental agencies;
- the quality, quantity and interpretation of available relevant data;
- assumptions concerning future commodity prices; and
- assumptions concerning future operating costs, severance and ad valorem taxes, development costs and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items, or other items not identified below, may differ materially from those assumed in estimating reserves:

- the quantities of oil and natural gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future commodity prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on the average previous twelve months first-of-month prices preceding the date of the estimate and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- the amount and timing of actual production;
- levels of future capital spending;
- increases or decreases in the supply of or demand for oil, natural gas liquids and natural gas; and
- changes in governmental regulations or taxation.

Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. Therefore, the estimates of discounted future net cash flows in this report should not be construed as accurate estimates of the current market value of our proved reserves.

Our business requires substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the acquisition, exploration and development of oil and natural gas reserves. At December 31, 2017, we had approximately $322 million of debt outstanding under our credit facility (and total debt at December 31, 2017 of $2.7 billion), and we had approximately $1.7 billion of unused commitments under our credit facility. Expenditures for acquisition, exploration and development of oil and natural gas properties are the primary use of our capital resources. We incurred approximately $2.9 billion in acquisition, exploration and development costs during the year ended December 31, 2017. In February 2018, we announced our 2018 capital budget, excluding acquisitions, of approximately $2.0 billion with expected capital spending to range between $1.9 billion and $2.1 billion. Our 2018 capital budget, based on our current expectations of commodity prices and costs, is expected to be funded with our cash flows. We plan to spend approximately $2.3 billion over the next five years on future development costs associated with proved undeveloped reserves.

We intend to finance our future capital expenditures, other than significant acquisitions, through cash flow from operations and, if necessary, through borrowings under our credit facility. However, our cash flow from operations and access to capital are subject to a number of variables, including:

- the level of oil and natural gas we are able to produce from existing wells;
- our ability to transport our oil and natural gas to market;
- the prices at which our commodities are sold;
- the costs of producing oil and natural gas;
- global credit and securities markets;
- the ability and willingness of lenders and investors to provide capital and the cost of the capital;
- our ability to acquire, locate and produce new reserves;
- the impact of potential changes in our credit ratings; and
- our proved reserves.

We may not generate expected cash flows and may have limited ability to obtain the capital necessary to sustain our operations at current or anticipated levels. A decline in cash flow from operations or our financing needs may require us to revise our capital program or alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. Additional borrowings under our credit facility or the issuance of additional debt securities will require that a greater portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. In addition, our credit facility imposes certain limitations on our ability to incur additional indebtedness other than indebtedness under our credit facility. If we desire to issue additional debt securities other than as expressly permitted under our credit facility, we will be required to seek the consent of the lenders in accordance with the requirements of the credit facility, which consent may be withheld by the lenders at their discretion. Additional financing also may not be available on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

The failure to obtain additional financing could result in a curtailment of our operations relating to the development of our undeveloped acreage, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our production, revenues and results of operations.

A decline in general economic, business or industry conditions could have a material adverse effect on our results of operations.

A global economic downturn, particularly with respect to the U.S. economy, and global financial and credit market disruptions reduce the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide, which can result in a slowdown in economic activity. Reduced worldwide demand for energy often results in lower commodity prices, which will reduce our cash flows and may affect our borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves as existing reserves are depleted. Lower commodity prices may also reduce the amount of oil and natural gas that we can produce economically, which could ultimately decrease our net revenue and profitability.

Recently enacted legislation will affect our tax position; however, certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated. Additional state taxes on oil and natural gas extraction may be imposed, as a result of future legislation.

In December 2017, Congress enacted the budget reconciliation act commonly referred to as the Tax Cuts and Jobs Act (“TCJA”). The law made significant changes to U.S. federal income tax laws, including reducing the corporate income tax rate from 35 percent to 21 percent, repealing the corporate alternative minimum tax (“AMT”), partially limiting the deductibility of interest expense and net operating losses (“NOLs”), eliminating the deduction for certain U.S. production activities and allowing the immediate deduction of certain new investments in lieu of depreciation expense over time. Many aspects of the TCJA are unclear and may not be clarified for some time. We will continue to monitor any new administrative guidance or tax law interpretation.

In recent years, U.S. lawmakers have proposed certain significant changes to U.S. tax laws applicable to oil and gas companies. These changes include, but are not limited to: (i) the elimination of current deductions for intangible drilling and development costs; (ii) the repeal of the percentage depletion allowance for oil and natural gas properties; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. Although these changes were not included in the TCJA, it is unclear whether any such changes will be enacted or if enacted, when such changes could be effective. If such proposed changes were to be enacted, as well as any similar changes in state law, it could eliminate or postpone certain tax deductions that are currently available to us with respect to oil and natural gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Additionally, future legislation could be enacted that increases the taxes or fees imposed on oil and natural gas extraction. Any such legislation could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil and natural gas.

Our ability to use our existing net operating loss carryforwards or other tax attributes could be limited.

At December 31, 2017, we had approximately $122 million of federal NOL carryforwards available to offset against future taxable income. These NOL carryforwards, generated prior to the effective date of new limitations on utilization of NOLs imposed by the TCJA, are allowable as a deduction against 100 percent of taxable income in future years but will expire in the tax year 2036. Utilization of any NOL depends on many factors, including our ability to generate future taxable income, which cannot be assured. In addition, Section 382 of the Internal Revenue Code of 1986, as amended ("Section 382"), generally imposes an annual limitation on the amount of NOLs that may be used to offset taxable income when a corporation has undergone an "ownership change" (as determined under Section 382). An ownership change generally occurs if one or more stockholders (or groups of stockholders) who are each deemed to own at least five percent of our stock change their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. In the event that an ownership change has occurred, or were to occur, utilization of our NOLs would be subject to an annual limitation under Section 382, determined by multiplying the value of our equity at the time of the ownership change by the applicable long-term tax-exempt rate as defined in Section 382, and potentially increased for certain gains recognized within five years after the ownership change if we have a net built-in gain in our assets at the time of the ownership change. Any unused annual limitation may be carried over to later years. We do not believe that an ownership change has occurred as a result of our recent equity offerings or our issuance of shares in connection with various acquisitions. As such, Section 382 was not expected to limit our ability to utilize our NOL carryforward or any other tax attribute at December 31, 2017. Future ownership changes or future regulatory changes could limit our ability to utilize our NOLs. To the extent we are not able to offset our future income with our NOLs, this could adversely affect our operating results and cash flows once we attain profitability.

We have substantial indebtedness and may incur substantially more debt. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We had approximately $2.7 billion of outstanding debt at December 31, 2017. At December 31, 2017, commitments from our bank group were $2.0 billion, of which $1.7 billion was unused commitments.

As a result of our indebtedness, we use a portion of our cash flow to pay interest, which reduces the amount we have available to fund our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our indebtedness under our credit facility is at a variable interest rate, and so a rise in interest rates will generate greater interest expense to the extent we do not have applicable interest rate fluctuation hedges. The amount of our debt may also cause us to be more vulnerable to economic downturns and adverse developments in our business.

We may incur substantially more debt in the future. Our credit facility and the indentures governing our senior notes contain restrictions on our incurrence of additional indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness in compliance with these restrictions. Moreover, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness under the indentures.

Any increase in our level of indebtedness could have adverse effects on our financial condition and results of operations, including imposing additional cash requirements on us in order to support interest payments, increasing our vulnerability to adverse changes in general economic and industry conditions and limiting our ability to sell assets, engage in strategic transactions or obtain additional financing for working capital, capital expenditures, general corporate and other purposes. If we incur additional debt, the related risks that we now face could intensify. A higher level of indebtedness also increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance which is affected by general economic conditions and financial, business and other factors, many of which are beyond our control.

If we are unable to comply with the restrictions and covenants in the agreements governing our indebtedness, there could be a default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional equity on terms that we may not find attractive if it may be done at all. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest, if any, on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the agreements governing our indebtedness, we could be in default under the terms of the agreements governing such indebtedness. In the event of such default:

- the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest;

- the lenders under our credit facility could elect to terminate their commitments thereunder and cease making further loans; and

- we could be forced into bankruptcy or liquidation.

If our operating performance declines, we may in the future need to obtain waivers under our credit facility to avoid being in default. If we breach our covenants under our credit facility and seek a waiver, we may not be able to obtain a waiver from the required lenders. If this occurs, we would be in default under our credit facility, the lenders could exercise their rights, as described above, and we could be forced into bankruptcy or liquidation.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

We receive debt credit ratings from S&P Global Ratings (“S&P”), Moody’s Investors Service, Inc. (“Moody’s”) and Fitch Ratings (“Fitch”), which are subject to regular reviews. In August 2017, our long-term debt was assigned a first-time investment grade rating by Fitch, and our rating by S&P was raised to an investment grade rating. In determining our ratings, the agencies consider a number of qualitative and quantitative factors including, but not limited to: the industry in which we operate, production growth opportunities, liquidity, debt levels and asset and reserve mix.

A downgrade in our credit ratings could (i) negatively impact our costs of capital and our ability to effectively execute aspects of our strategy, (ii) affect our ability to raise debt in the public debt markets, and the cost of any new debt could be

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much higher than our outstanding debt and (iii) negatively affect our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing. In September 2017, we elected to enter into an Investment Grade Period under our credit facility, which had the effect of releasing all collateral formerly securing the credit facility. If we are unable to maintain credit ratings of “Ba2” or better from Moody’s and “BB” or better from S&P, the Investment Grade Period will automatically terminate and cause the credit facility to once again be secured by a first lien on substantially all of our oil and natural gas properties and by a pledge of the equity interests in our subsidiaries. These and other impacts of a downgrade in our credit ratings could have a material adverse effect on our business, financial condition and results of operations.

As of the filing of this report, no additional changes in our credit ratings have occurred; however, we cannot be assured that our credit ratings will not be downgraded in the future.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant delays, costs and liabilities as a result of environmental, occupational health and safety requirements applicable to our oil and natural gas exploration, development and production, and related saltwater disposal activities. These delays, costs and liabilities could arise under a wide range of federal, state and local laws and regulations relating to protection of the environment, occupational health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations.

Strict as well as joint and several liability for a variety of environmental costs may be imposed on us under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. Costs stemming from environmental remediation obligations could be significant and adversely affect our financial condition and results of operations. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. No assurance can be given that continued compliance with existing or future environmental laws and regulations will not result in a curtailment of production or processing activities or result in a material increase in the costs of production, development, exploration or processing operations. If we are not able to recover the resulting costs through insurance or increased revenues, our production, revenues and results of operations could be adversely affected.

Our producing properties are concentrated in the Permian Basin of southeast New Mexico and west Texas, making us vulnerable to risks associated with operating in one major geographic area. In addition, substantially all of our proved reserves are attributable to this area.

Our producing properties are geographically concentrated in the Permian Basin of southeast New Mexico and west Texas. At December 31, 2017, substantially all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we are exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, severe weather events, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or natural gas liquids.

In addition to the geographic concentration of our producing properties described above, at December 31, 2017, approximately: (i) 35 percent of our proved reserves were attributable to the Northern Delaware Basin core area that primarily targets the Avalon shale and Bone Spring and Wolfcamp formations; (ii) 15 percent of our proved reserves were attributable to the Southern Delaware Basin core area that primarily targets the Bone Spring and Wolfcamp formations; (iii) 32 percent of our proved reserves were attributable to the Midland Basin core area that primarily targets the Wolfcamp and Spraberry formations; and (iv) 18 percent of our proved reserves were attributable to the New Mexico Shelf core area that primarily targets the Yeso formation, which includes both the Paddock and Blinebry intervals underlying our oil and natural gas properties located in southeast New Mexico. This concentration of assets exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

We periodically assess our unproved oil and natural gas properties for impairment and could be required to recognize non-cash charges to earnings of future periods.

At December 31, 2017, we carried unproved property costs of $2.7 billion. GAAP requires periodic assessment of these costs on a project-by-project basis. Our assessment considers future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales, expiration of all or a portion of the projects, contracts and permits relevant to such projects. Based on our assessments, we may determine that we are unable to fully recover the cost invested in each project, and we will recognize non-cash charges to earnings in future periods if such determination is made.

Future price declines could result in a reduction in the carrying value of our proved oil and natural gas properties, which could adversely affect our results of operations.

Declines in commodity prices may result in our having to make substantial downward adjustments to the value of our estimated proved reserves. If this occurs, or if our estimates of production or economic factors change, accounting rules may require us to write-down, as a non-cash charge to earnings, the carrying value of our proved oil and natural gas properties for impairments. We are required to perform impairment tests on proved assets whenever events or changes in circumstances warrant a review of our proved oil and natural gas properties. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our oil and natural gas properties, the carrying value may not be recoverable and therefore require a write-down. The primary factors that may affect management’s estimates of future cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities and (v) prevailing market rates of income and expenses from integrated assets. We may incur impairment charges in the future, which could materially adversely affect our results of operations in the period incurred. We recorded impairment charges of $1.5 billion and $61 million in 2016 and 2015, respectively. We did not incur an impairment charge in 2017.

Our commodity price risk management program may cause us to forego additional future profits or result in us making cash payments to our counterparties.

To reduce our exposure to changes in the prices of commodities, we have entered into and may in the future enter into additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Commodity price risk management arrangements expose us to the risk of financial loss and may limit our ability to benefit from increases in commodity prices in some circumstances, including the following:

- market prices may exceed the prices which we are contracted to receive, resulting in our need to make significant cash payments to our counterparties;

- there may be a change in the expected differential between the underlying price in a commodity price risk management agreement and actual prices received; or

- the counterparty to a commodity price risk management contract may default on its contractual obligations to us.

Our commodity price risk management activities could have the effect of reducing our net income and the value of our securities. At December 31, 2017, we had a net derivative liability of approximately $379 million. An average increase in the commodity price of $5.00 per barrel of oil and $0.50 per MMBtu for natural gas from the commodity price at December 31, 2017 would have resulted in an increase in our net liability of approximately $327 million. We may continue to incur significant gains or losses in the future from our commodity price risk management activities to the extent market prices increase or decrease and our derivatives contracts remain in place.

Our identified inventory of drilling locations and recompletion opportunities are scheduled over several future years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have identified and scheduled the drilling of certain locations as an estimation of our future multi-year development activities on our existing acreage. These identified locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including those described elsewhere in these risk factors. Because of these and other potential uncertainties, we may never drill the potential locations we have identified or produce oil or natural gas from these or any other potential locations. As such, our actual development activities may materially differ from those presently identified, which could adversely affect our production, reserves, revenues and results of operations.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flow, our ability to raise capital and the value of our securities.

Unless we conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. The value of our securities and our ability to raise capital will be adversely impacted if we are not able to replace our reserves that are depleted by production or replace our declining production with new production. We may not be able to develop, exploit, find or acquire sufficient additional reserves or replace our current and future production.

The Standardized Measure and PV-10 of our estimated reserves are not accurate estimates of the current fair value of our estimated proved oil and natural gas reserves.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. Our non-GAAP financial measure, PV-10, is a similar reporting convention that we have disclosed in this report. Both measures require the use of operating and development costs prevailing as of the date of computation. Consequently, they will not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and natural gas properties. Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the 10 percent discount factor, which is required by the rules and regulations of the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our company or the oil and natural gas industry in general. Therefore, Standardized Measure and PV-10 included in this report should not be construed as accurate estimates of the current fair value of our proved reserves.

Our reserve estimates and our computation of future net cash flows are based on SEC pricing of (i) $47.79 per Bbl WTI posted oil price and (ii) $2.98 per MMBtu Henry Hub spot natural gas price, adjusted for location and quality by property. The SEC pricing for reserves as of December 31, 2017 is lower than the NYMEX oil price of $61.68 per Bbl at February 16, 2018 but higher than the NYMEX natural gas price of $2.56 per MMBtu at February 16, 2018. If average oil prices were $5.00 per barrel lower than the average price we used, our PV-10 at December 31, 2017 would have decreased from $8.5 billion to $7.4 billion. If average natural gas prices were $0.50 per MMBtu lower than the average price we used, our PV-10 at December 31, 2017 would have decreased from $8.5 billion to $8.1 billion. Any adjustments to the estimates of proved reserves or decreases in the price of our commodities may decrease the value of our securities.

We may be unable to make attractive acquisitions or successfully integrate acquired companies or assets, and any inability to do so may disrupt our business and hinder our ability to grow.

One aspect of our business strategy calls for acquisitions of businesses or assets that complement or expand our current business. We may not be able to identify attractive acquisition opportunities, including acreage trades. Even if we do identify attractive candidates, pursuing such acquisitions may be distracting to management and costly to the Company. We may not be able to complete the acquisition of them or do so on commercially acceptable terms.

In addition, our credit facility and the indentures governing our senior notes impose certain limitations on our ability to enter into mergers or combination transactions. Our credit facility and the indentures governing our senior notes also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses or assets. If we desire to engage in an acquisition that is otherwise prohibited by our credit facility or the indentures governing our senior notes, we will be required to seek the consent of our lenders or the holders of the senior notes in accordance with the requirements of the credit facility or the indentures, which consent may be withheld by the lenders under our credit facility or such holders of senior notes at their sole discretion.

If we acquire another business or assets, we could have difficulty integrating its operations, systems, management and other personnel and technology with our own. These difficulties could disrupt our ongoing business, distract our management and employees, increase our expenses and adversely affect our results of operations. In addition, we may incur additional debt or issue additional equity to pay for any future acquisitions, subject to the limitations described above.

Any acquisition we complete is subject to substantial risks that could adversely affect our business, including the risk that our acquisitions may prove to be worth less than what we paid because of uncertainties in evaluating recoverable reserves and could expose us to potentially significant liabilities.

We obtained a significant portion of our current reserve base through acquisitions of producing properties and undeveloped acreage. We expect that acquisitions, including acreage trades, will continue to contribute to our future growth. In connection with these and potential future acquisitions, we are often only able to perform limited due diligence. The success of any acquisition involves potential risks, including among other things:

- the inability to estimate accurately the costs to develop the reserves, recoverable volumes of reserves, rates of future production and future net cash flows attainable from the reserves;

- the assumption of unknown liabilities, including environmental liabilities, and losses or costs for which we are not indemnified or for which the indemnity we receive is inadequate;

- the effect on our liquidity or financial leverage of using available cash or debt to finance acquisitions;

- the diversion of management’s attention from other business concerns; and

- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets.

Successful acquisitions of oil and natural gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing of recovering reserves, exploration potential, future commodity prices, operating costs and potential environmental, regulatory and other liabilities. Such assessments are inexact, and we cannot make these assessments with a high degree of accuracy. In connection with our assessments, we perform a review of the acquired properties that we believe to be generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise.

There may be threatened, contemplated, asserted or other claims against the acquired assets related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We are sometimes able to obtain contractual indemnification for preclosing liabilities, including environmental liabilities, but we generally acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties. In addition, even when we are able to obtain such indemnification from the sellers, these indemnification obligations usually expire over time and expose us to potential unindemnified liabilities, which could materially adversely affect our production, revenues and results of operations.

Shortages of oilfield equipment, services and qualified personnel could delay our drilling program and increase the prices we pay to obtain such equipment, services and personnel.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with commodity prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher commodity prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. These types of shortages or price increases would decrease our profit margin, cash flow and operating results, or restrict our ability to drill the wells and conduct the operations which we currently have planned and budgeted or which we may plan in the future.

Our exploration and development drilling may not result in commercially productive reserves.

Drilling activities are subject to many risks, including the risk that commercially productive reservoirs will not be encountered. New wells that we drill may not be productive, or we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or may be produced economically. Drilling for oil and natural gas often involves unprofitable results, not only from dry holes but also from wells that are productive but do not produce sufficient net reserves to return a profit at then realized prices after deducting drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- risks associated with drilling horizontal wells and extended lateral lengths, such as deviating from the desired drilling zone or not running casing or tools consistently through the wellbore, particularly as lateral lengths get longer;
- pressure or irregularities in formations;
- equipment failures or accidents;
- fracture stimulation accidents or failures;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and

- increases in the cost of, or shortages or delays in the availability of, electricity, water, supplies, materials, drilling or workover rigs, equipment and services.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. In addition, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities, including well stimulation and completion activities such as hydraulic fracturing, are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- abnormally pressured or structured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- blowouts, cratering, fires, explosions and ruptures of pipelines;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- damage to and destruction of property and equipment;

- damage to natural resources due to underground migration of hydraulic fracturing fluids;
- pollution and other environmental damage, including spillage or mishandling of recovered hydraulic fracturing fluids;
- regulatory investigations and penalties;
- loss of well location, acreage, expected production and related reserves;
- suspension or delay of our operations;
- substantial liability claims; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable, and we do not insure for business interruption of the loss of a well. The occurrence of an event that is not covered or not fully covered by insurance could have a material adverse effect on our production, revenues and results of operations.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Some of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, those companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost and other challenges to attract and retain qualified personnel may increase substantially in the future. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. Our failure to acquire properties, market oil and natural gas and secure trained personnel and adequately compensate personnel could have a material adverse effect on our production, revenues and results of operations.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas processing or transportation arrangements may hinder our access to oil, natural gas and natural gas liquid markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil, natural gas and natural gas liquids, the proximity of reserves to pipelines and terminal facilities, competition for such facilities and the inability of such facilities to gather, transport or process our production due to shutdowns or curtailments arising from mechanical, operational or weather related matters, including hurricanes and other severe weather conditions. Our ability to market our production depends in substantial part on the availability and capacity of gathering and transportation systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could have a material adverse effect on our business, financial condition and results of operations. We may be required to shut in or otherwise curtail production from wells due to lack of a market or inadequacy or unavailability of oil, natural gas liquid or natural gas pipeline or gathering, transportation or processing capacity. If that were to occur, then we would be unable to realize revenue from those wells until suitable arrangements were made to market our production.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, timing, manner or feasibility of conducting our operations or that may subject us to fines or penalties for any failure to comply.

Our oil and natural gas exploration, development and production, and related saltwater disposal operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, local and governmental authorities. We may incur substantial costs and experience delays in order to maintain compliance with these existing laws and regulations. If we fail to comply with the existing laws and regulations, we may incur additional costs, including fines and penalties, in order to come back into compliance. In addition, our costs of compliance may increase or our operations may be otherwise adversely affected if existing laws and regulations are revised or reinterpreted or if the government agencies responsible for enforcing certain existing laws and regulations applicable to us change their priorities or policies, or if new laws and regulations become applicable to our operations. These and other costs could have a material adverse effect on our production, revenues and results of operations.

The adoption of derivatives legislation by Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us, which participate in that market. This legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Act”), became law on July 21, 2010 and requires the Commodity Futures Trading Commission (the “CFTC”) and the SEC to promulgate rules and regulations implementing the Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented, and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents; however this initial position limits rule was vacated by the U.S. District Court for the District of Columbia in September 2012. The CFTC has subsequently issued proposals for new rules that would place position limits on certain core futures contracts and equivalent swap contracts for or linked to certain physical commodities, subject to certain exceptions for bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps subject to mandatory clearing and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. Although we expect to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If our swaps do not qualify for the commercial end-user exception from mandatory clearing, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions or our ability to hedge may be impacted. The ultimate effect of the rules and any additional regulations on our business is uncertain at this time.

In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception from such margin requirements for swaps entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, the posting of collateral could reduce our liquidity and cash available for capital expenditures and our ability to manage commodity price volatility and the volatility in cash flows.

The full impact of the Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. When fully implemented, the Act and any new regulations could increase the operational and transactional cost of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize and restructure our existing derivatives contracts, impact commodity prices and affect the number and/or creditworthiness of available counterparties. If we reduce our use of derivatives as a result of the Act and regulations implementing the Act, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

The loss of our chief executive officer or other key personnel could negatively impact our ability to execute our business strategy.

We depend, and will continue to depend in the foreseeable future, on the services of our chief executive officer, Timothy A. Leach, and other officers and key employees who have extensive experience and expertise in evaluating and analyzing producing oil and natural gas properties and drilling prospects, maximizing production from oil and natural gas properties, marketing oil and natural gas production, and developing and executing acquisition, financing and hedging strategies. Our ability to hire and retain our officers and key employees is important to our continued success and growth. The unexpected loss of the services of one or more of these individuals could negatively impact our ability to execute our business strategy.

Because we do not operate and therefore control the development of certain of the properties in which we own interests, we may not be able to produce economic quantities of oil and natural gas in a timely manner.

At December 31, 2017, approximately 7 percent of our proved reserves were attributable to properties for which we were not the operator. As a result, the success and timing of drilling and development activities on properties operated by others depend upon a number of factors that are beyond our control, including:

- the nature and timing of drilling and operational activities controlled by others;

- the timing and amount of the operators’ capital expenditures;

- the operators' expertise and financial resources;
- the approval of other participants in such properties; and
- the selection and application of suitable technology.

If drilling and development activities are not conducted on these properties or are not conducted as we expect, we may be unable to increase our production or offset normal production declines or we will be required to write-off the reserves attributable to such properties, which may adversely affect our production, revenues and results of operations.

A terrorist or cyber attack or armed conflict could harm our business by decreasing our revenues and increasing our costs.

Terrorist activities, anti-terrorist efforts, cyber-attacks and other armed conflict involving the United States may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur or escalate, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our production and causing a reduction in our revenue. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if significant infrastructure or facilities used for the production, transportation, processing or marketing of oil and natural gas production are destroyed or damaged. Additionally, as an oil and natural gas producer, we constantly face various cybersecurity threats, including threats to gain unauthorized access to sensitive information or to render data or systems unusable, and there can be no assurance that our implementation of various procedures and controls to monitor and mitigate security threats will be sufficient to prevent security breaches from occurring. Costs for insurance, recovery, remediation and other security measures may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Our reliance on information technology, including those hosted by third parties, exposes us to cyber security risks that could affect our business, financial condition or reputation and increase compliance challenges.

We rely extensively on information technology systems, including Internet sites, computer software, data hosting facilities and other hardware and platforms, some of which are hosted by third parties, to assist in conducting our business. Our information technology systems, as well as those of third parties we use in our operations, may be vulnerable to a variety of evolving cybersecurity risks, such as those involving unauthorized access, denial-of-service attacks, malicious software, data privacy breaches by employees, insiders or others with authorized access, cyber or phishing-attacks, ransomware, malware, social engineering, physical breaches or other actions.

Although we have implemented information technology controls and systems that are designed to protect information and mitigate the risk of data loss and other cybersecurity risks, such measures cannot entirely eliminate cybersecurity threats, and the enhanced controls we have installed may be breached. If our information technology systems cease to function properly or our cybersecurity is breached, we could suffer disruptions to our normal operations which may include drilling, completion, production and corporate functions. A cyber attack involving our information systems and related infrastructure, or that of our business associates, could negatively impact our operations in a variety of ways, including but not limited to, the following:

- Unauthorized access to seismic data, reserves information, strategic information, or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;

- Data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;

- Data corruption or operational disruptions of production-related infrastructure could result in a loss of production, or accidental discharge;

- A cyber attack on a vendor or service provider could result in supply chain disruptions which could delay or halt our major development projects;

- A cyber attack on third party gathering, pipeline, or rail transportation systems could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues;

- A cyber attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;

- A cyber attack which halts activities at a power generation facility or refinery using natural gas as feed stock could have a significant impact on the natural gas market, resulting in reduced demand for our production, lower natural gas prices, and reduced revenues;

- A cyber attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;

- A cyber attack on our automated and surveillance systems could cause a loss in production and potential environmental hazards;

- A deliberate corruption of our financial or operating data could result in events of non-compliance which could then lead to regulatory fines or penalties; and

- A cyber attack resulting in the loss or disclosure of, or damage to, our or any of our customer's or supplier's data or confidential information could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps.

All of the above could negatively impact our operational and financial results. Additionally, certain cyber incidents, such as surveillance, may remain undetected for an extended period. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities. Additionally, the growth of cyber attacks has resulted in evolving legal and compliance matters which impose significant costs that are likely to increase over time.

Risks Related to Our Common Stock

Our certificate of incorporation, our bylaws and Delaware law contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation, our bylaws and Delaware law could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- the organization of our board of directors as a classified board, which allows no more than approximately one-third of our directors to be elected each year;

- stockholders cannot remove directors from our board of directors except for cause and then only by the holders of not less than 66 2/3 percent of the voting power of all outstanding voting stock;

- the prohibition of stockholder action by written consent; and

- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Because we have not historically and do not have immediate plans to pay dividends on our common stock, investors are currently limited to stock appreciation for a return on their investment in us.

We do not have plans to pay cash dividends on our common stock in the near future. We currently intend to retain future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Covenants contained in our credit facility and the indentures governing our senior notes could limit the payment of dividends; however, at December 31, 2017, under our covenants we could pay dividends in excess of $1 billion. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize an immediate return on their investment.

The availability of shares for sale in the future could reduce the market price of our common stock.

In the future, we may issue securities to raise cash for acquisitions. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into, or exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our company, reduce our earnings per share and have an adverse impact on the price of our common stock.

In addition, sales of a substantial amount of our common stock in the public market, or the perception that these sales may occur, could reduce the market price of our common stock. This could also impair our ability to raise additional capital through the sale of our securities.

Item 1B. Unresolved Staff Comments

There are no unresolved staff comments.

Item 2. Properties

Our Oil and Natural Gas Reserves

The estimates of our proved reserves at December 31, 2017, all of which were located in the United States, were based on evaluations prepared by the independent petroleum engineering firms of Cawley, Gillespie & Associates, Inc. (“CGA”) and Netherland, Sewell & Associates, Inc. (“NSAI”) (collectively, our “external engineers”). Reserves were estimated in accordance with guidelines established by the SEC and the Financial Accounting Standards Board (the “FASB”).

Internal controls. Our proved reserves are estimated at the property level by external engineers and compiled for reporting purposes by our corporate reservoir engineering staff. We maintain our internal evaluations of our reserves in a secure reserve engineering database. The corporate reservoir engineering staff interact with our internal staff of petroleum engineers, geoscience professionals and land professionals in each of our operating areas and with accounting and marketing employees to obtain the necessary data for the reserves estimation process. Reserves are reviewed and approved internally by members of our senior management and the reserves committee, a committee of our Board of Directors.

Our internal professional staff works closely with our external engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their preparation of our reserves.

Qualifications of responsible technical persons

J. Steve Guthrie has been our Senior Vice President of Business Operations and Engineering since November 2013. Mr. Guthrie previously served as the Vice President of Texas, the Texas Asset Manager and Corporate Engineering Manager. Prior to joining the Company, Mr. Guthrie was employed by Moriah Resources as Business Development Manager, by Henry Petroleum in various engineering and operations capacities and by Exxon in several engineering and operations positions. Mr. Guthrie is a graduate of Texas Tech University with a Bachelor of Science degree in Petroleum Engineering.

Rick Morton joined the Company in 2011 as Corporate Engineering Manager. Prior to joining the Company, Mr. Morton served as Division Acquisition Coordinator for EOG Resources, Inc. Mr. Morton was also previously employed by Southwest Royalties, Inc. as Vice President and Exploitation Manager and by Merit Energy Company in various engineering positions. Mr. Morton began his career in 1983 with Arco Oil and Gas Company as an Operations/Analytical Engineer before moving to a Production Supervisor position. He is a graduate of Texas A&M University with a Bachelor of Science degree in Petroleum Engineering.

CGA. Approximately 53 percent of the proved reserves estimates shown herein at December 31, 2017 have been independently prepared by CGA, a leader of petroleum property analysis for industry and financial institutions. CGA was founded in 1960 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Within CGA, the technical person primarily responsible for preparing the estimates set forth in the CGA letter dated January 19, 2018, filed as an exhibit to this Annual Report on Form 10-K, was Mr. Zane Meekins. Mr. Meekins has been a practicing consulting petroleum engineer at CGA since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 30 years of practical experience in petroleum engineering, with over 28 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a Bachelor of Science degree in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

NSAI. Approximately 47 percent of the proved reserve estimates shown herein at December 31, 2017 have been independently prepared by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical person primarily responsible for preparing the estimates set forth in the NSAI letter dated January 24, 2018, filed as an exhibit to this Annual Report on Form 10-K, was Mr. Craig H. Adams. Mr. Adams, a Licensed Professional Engineer in the State of Texas (License No. 68137), has been practicing consulting petroleum engineering at NSAI since 1997 and has over 11 years of prior industry experience. He graduated from Texas Tech University in 1985 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Adams meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

Our oil and natural gas reserves. The following table sets forth our estimated proved oil and natural gas reserves at December 31, 2017. Our reserve estimates and our computation of future net cash flows are based on SEC pricing of (i) $47.79 per Bbl WTI posted oil price and $2.98 per MMBtu Henry Hub spot natural gas price, adjusted for location and quality by property.

	Oil (MMBbl)	Natural Gas (Bcf)	Total (MMBoe)
Core Operating Areas:			
Northern Delaware Basin	149	878	295
Southern Delaware Basin	92	214	128
Midland Basin	175	546	266
New Mexico Shelf	84	404	151
Other	-	1	-
Total	500	2,043	840

The following table sets forth our estimated proved reserves by category at December 31, 2017:

	Oil (MMBbl)	Natural Gas (Bcf)	Total (MMBoe)	Percent of Total
Proved developed producing	324	1,481	571	68%
Proved developed non-producing	12	31	17	2%
Proved undeveloped	164	531	252	30%
Total proved	500	2,043	840	100%
Total proved developed	336	1,512	588	70%

Changes to proved reserves. The following table sets forth the changes in our proved reserve volumes by area during the year ended December 31, 2017 (in MMBoe):

	Production	Extensions and Discoveries	Purchases of Minerals-in-Place	Sales of Minerals-in-Place	Revisions of Previous Estimates
Core Operating Areas:					
Northern Delaware Basin	(33)	63	15	-	16

Southern Delaware Basin	(10)	29	4	-	(4)
Midland Basin	(16)	77	14	(4)	2
New Mexico Shelf	(11)	5	1	-	(28)
Total	(70)	174	34	(4)	(14)

Extensions and discoveries. Extensions and discoveries of approximately 174 MMBoe are primarily the result of our continued success from our extension and infill horizontal drilling programs in our core operating areas. Proved developed reserves increased approximately 82 MMBoe due to our exploratory drilling activity in 2017. Based upon this activity, approximately 92 MMBoe of new proved undeveloped locations were added.

Purchases and sales of minerals-in-place. Our purchases of minerals-in-place are composed of approximately 11 MMBoe from the July 2017 Midland Basin acquisition, 8 MMBoe from the January 2017 Northern Delaware Basin acquisition and 15 MMBoe from various other acquisitions throughout the year. Our sales of minerals-in-place are composed of approximately 4 MMBoe from various divestitures throughout the year.

Revisions of previous estimates. Revisions of previous estimates are composed of (i) 61 MMBoe of negative revisions due to proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within five years of the date of their initial recognition as required by SEC rules due to a shift in our capital program to generally focus more on large-scale development projects in certain areas, (ii) 29 MMBoe of positive price revisions and (iii) 18 MMBoe of positive technical and performance revisions. Our proved reserves at December 31, 2017 were determined using the SEC prices of $47.79 per Bbl of oil for WTI and $2.98 per MMBtu of natural gas for Henry Hub spot, compared to corresponding prices of $39.25 per Bbl of oil and $2.48 per MMBtu of natural gas at December 31, 2016.

Proved undeveloped reserves. At December 31, 2017, we had approximately 252 MMBoe of proved undeveloped reserves as compared to 254 MMBoe at December 31, 2016.

The following table summarizes the changes in our proved undeveloped reserves during 2017 (in MMBoe):

At December 31, 2016	254
Extensions and discoveries	92
Purchases of minerals-in-place	11
Revisions of previous estimates	(39)
Conversion to proved developed reserves	(66)
At December 31, 2017	252

Extensions and discoveries. Extensions and discoveries of approximately 92 MMBoe are primarily the result of new proved undeveloped locations that were added.

Revisions of previous estimates. Net negative revisions of previous estimates of approximately 39 MMBoe are primarily attributable to (i) 61 MMBoe of negative revisions due to proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within five years of the date of their initial recognition due to a shift in our capital program to generally focus more on large-scale development projects in certain areas, (ii) 6 MMBoe of positive price revisions and (iii) 16 MMBoe of net positive performance and miscellaneous revisions.

Conversion to proved developed reserves. The following table sets forth proved undeveloped reserves converted to proved developed reserves and the investment required to convert proved undeveloped reserves to proved developed reserves during the year ended December 31, 2017:

Proved Undeveloped Reserves Converted to Proved Developed Reserves	**Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves**

Oil (MMBbl)	Natural Gas (Bcf)	Total (MMBoe)	(in millions)
43	141	66	$ 619(a)

(a) Of this amount, approximately $79 million was spent in 2017 on proved undeveloped reserves that were not converted to proved developed reserves by December 31, 2017.

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The following table sets forth the estimated timing and cash flows of developing our proved undeveloped reserves at December 31, 2017 (dollars in millions):

Years Ended December 31, (a)	Future Production (MMBoe)		Future Cash Inflows (b)		Future Production Costs		Future Development Costs		Future Net Cash Flows
2018	9	$	346	$	(51)	$	(709)	$	(415)
2019	20		796		(120)		(623)		53
2020	26		987		(158)		(611)		219
2021	25		918		(153)		(228)		537
2022	20		728		(131)		(85)		512
Thereafter	152		5,656		(1,403)		-		4,253
Total	252	$	9,431	$	(2,016)	$	(2,256)	$	5,159

(a) Beginning in 2018 and thereafter, the production and cash flows represent the drilling results from the respective year plus the incremental effects from the results of proved undeveloped drilling from previous years.
(b) Computation is based on SEC pricing of (i) $47.79 per Bbl WTI posted oil price and (ii) $2.98 per MMBtu Henry Hub spot natural gas price, adjusted for location and quality by property.

Historically, our drilling programs were substantially funded from our cash flow and borrowings from our credit facility. Based on our current expectations over the next five years of our cash flows and drilling programs, which includes drilling of proved undeveloped and unproven locations, we believe that we can continue to substantially fund our drilling activities from our cash flow and with borrowings from our credit facility, if needed.

Developed and Undeveloped Acreage

The following table presents our total gross and net developed and undeveloped acreage by area at December 31, 2017:

	Developed Acres (a)	Undeveloped Acres (b)	Total Acres

(in thousands)	Gross	Net	Gross	Net	Gross	Net
Core Operating Areas:						
Northern Delaware Basin	194	131	179	128	373	259
Southern Delaware Basin	72	56	74	38	146	94
Midland Basin	187	110	78	44	265	154
New Mexico Shelf	69	45	52	33	121	78
Total	522	342	383	243	905	585

(a) Developed acres are acres attributable or assigned to wells producing economic quantities of oil or natural gas and do not include undrilled acreage held by production.

(b) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or natural gas regardless of whether such acreage contains proved reserves.

The following table sets forth the future expiration amounts of our gross and net undeveloped acreage at December 31, 2017 by core area:

	2018		2019		2020		Thereafter	
(in thousands)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Core Operating Areas:								
Northern Delaware Basin	3	3	3	3	2	1	9	9
Southern Delaware Basin	15	8	9	5	10	1	-	-
Midland Basin (a)	1	-	-	1	1	-	-	-
New Mexico Shelf	2	-	1	-	2	1	1	1
Total	21	11	13	9	15	3	10	10

(a) Expiring net acres are greater than gross acres in our Midland Basin core area in 2019 as certain leases contain undivided interests and have multiple net acreage expiration dates within the same tract of land. Expirations of net acres are shown in the year they occur, while the expirations of gross acres are shown in the final year of net acre expiration.

At December 31, 2017, we had approximately 68,000 gross and 47,000 net acres subject to a continuous development clause (“CDC”). Acres subject to a CDC typically require the commencement of drilling a well within six to twelve months of the completion of the most recent well on the related lease. Historically, we have not experienced material expiration of acres due to non-compliance with a CDC, and we do not anticipate any material expirations during 2018.

Drilling Activities

For summary tables that set forth information with respect to wells drilled and completed for the years ended December 31, 2017, 2016 and 2015, see “Item 1. Business—Drilling Activities.”

Our Production, Prices and Expenses

For a summary table that sets forth information concerning our production and operating data from operations for the years ended December 31, 2017, 2016 and 2015, see “Item 1. Business—Our Production, Prices and Expenses.”

Productive Wells

For a summary table that sets forth the number of productive oil and natural gas wells on our properties at December 31, 2017, 2016 and 2015, see “Item 1. Business—Productive Wells.”

Title to Our Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a more thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect defects affecting those properties, we are typically responsible for curing any such defects at our expense. We generally will not commence drilling operations on a property until we have cured known material title defects on such property. We have reviewed the title to substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on the most significant properties, and depending on the materiality of properties, we may obtain a title opinion or review or update previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens that we believe do not materially interfere with the use or affect our carrying value of the properties.

Item 3. Legal Proceedings

We are a party to proceedings and claims incidental to our business. While many of these other matters involve inherent uncertainty, we believe that the liability, if any, ultimately incurred with respect to such other proceedings and claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future results of operations. We will continue to evaluate proceedings and claims involving us on a regular basis and will establish and adjust any reserves as appropriate to reflect our assessment of the then current status of the matters.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Our common stock trades on the NYSE under the symbol "CXO." The following table shows, for the periods indicated, the high and low sales prices for our common stock, as reported on the NYSE.

	Price Per Share High	Price Per Share Low
2016:		
First Quarter	$ 107.00	$ 69.94
Second Quarter	$ 130.03	$ 95.87
Third Quarter	$ 137.83	$ 114.33
Fourth Quarter	$ 147.55	$ 123.88
2017:		
First Quarter	$ 145.60	$ 122.65
Second Quarter	$ 136.93	$ 112.73
Third Quarter	$ 134.03	$ 106.73
Fourth Quarter	$ 155.05	$ 128.86

On February 16, 2018, the last sales price of our common stock as reported on the NYSE was $146.52 per share.

As of February 16, 2018, there were 1,143 holders of record of our common stock.

Dividend Policy

We do not have plans to pay cash dividends on our common stock in the near future. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Covenants contained in our credit facility and the indentures governing our senior notes could limit the payment of dividends; however, at December 31, 2017, under our covenants we could pay dividends in excess of $1 billion. See Note 9 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Repurchases of Equity Securities

The following table sets forth our share repurchase activity for each period presented:

Period	Total number of shares withheld (a)	Average price per share		Total number of shares purchased as part of publicly announced plans	Maximum number of shares that may yet be purchased under the plan
October 1, 2017 - October 31, 2017	103	$	133.24	-	
November 1, 2017 - November 30, 2017	35	$	138.40	-	
December 1, 2017 - December 31, 2017	360	$	143.64	-	

(a) Represents shares that were withheld by us to satisfy tax withholding obligations of certain employees that arose upon the lapse of restrictions on restricted stock.

Item 6. Selected Financial Data

This section presents our selected historical consolidated financial data. The selected historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements. You should read the following data along with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the consolidated financial statements and related notes, each of which is included in this report.

Selected Historical Financial Information

Our results of operations for the periods presented below may not be comparable either from period to period or going forward for the following reasons:

- in March 2015, we issued 6.9 million shares of our common stock in a public offering at $107.49 per share, and we received net proceeds of approximately $742 million;

- in October 2015, we issued approximately 8.9 million shares of our common stock in a public offering at $92.50 per share, and we received net proceeds of approximately $794 million;

- in December 2015, we completed an acreage exchange with Clayton Williams Energy, Inc. that consolidated acres into a concentrated, operated position in the Southern Delaware Basin. We recognized a loss on disposition of assets of approximately $50 million related to the acreage exchange;

- in February 2016, we sold certain assets in the Northern Delaware Basin for proceeds of approximately $292 million and recognized a pre-tax gain of approximately $110 million;

- in March 2016, we completed an acquisition of 80 percent of a third-party seller’s interest in certain oil and natural gas properties and related assets in the Southern Delaware Basin. As consideration for the acquisition, we issued to the seller approximately 2.2 million shares of our common stock with an approximate value of $231 million, $146 million in cash and $40 million to carry a portion of the seller’s future development costs in these properties;

- in August 2016, we issued approximately 10.4 million shares of our common stock in a public offering at $130.90 per share and received net proceeds of approximately $1.3 billion. We used a portion of the net proceeds to finance part of the cash portion of the purchase price for the Reliance Acquisition and to fund part of the early redemption of our 7.0% unsecured senior notes due 2021 (the “7.0% Notes”) and the remainder for general corporate purposes;

- in September 2016, we redeemed the $600 million outstanding principal amount of the 7.0% Notes at a price equal to 103.5 percent of par. The redemption price included the make-whole premium for the early redemption, as determined in accordance with the indenture governing the 7.0% Notes. We also paid accrued and unpaid interest on the 7.0% Notes through September 19, 2016, the redemption date. We recorded a loss on extinguishment of debt related to the redemption of the 7.0% Notes of approximately $28 million. This amount includes $21 million associated with the make-whole premium paid for the early redemption of the 7.0% Notes and approximately $7 million of unamortized deferred loan costs;

- in October 2016, we completed the Reliance Acquisition. As consideration for the acquisition, we paid approximately $1.2 billion in cash and issued to the seller approximately 3.9 million shares of common stock with an approximate value of $0.5 billion;

- in December 2016, we issued $600 million in aggregate principal amount of 4.375% senior notes due 2025 (the “4.375% Notes”) at par, for which we received net proceeds of approximately $592 million. We used the net proceeds from the offering to fund the satisfaction and discharge of our obligations under the indenture of the $600 million outstanding principal amount of our 6.5% unsecured senior notes due 2022 (the “6.5% Notes”) at a price equal to 103.25 percent of par;

- in January and April 2017, we closed on the two-part acquisition of approximately 17,600 net acres in the Northern Delaware Basin. As consideration for the entire acquisition, we paid approximately $160 million in cash, of which $43 million was held in escrow at December 31, 2016, and issued to the seller approximately 2.2 million shares of our common stock with an approximate carrying value of $291 million;

- in February 2017, we closed on the divestiture of our ownership interest in ACC. We and our joint venture partner entered into separate agreements to sell 100 percent of our respective ownership interests in ACC. After adjustments for debt and working capital, we received cash proceeds from the sale of approximately $801 million. After direct transaction costs, we recorded a pre-tax gain on disposition of assets of approximately $655 million. Our net investment in ACC at the time of closing was approximately $129 million;

- in July 2017, we completed an acquisition in the Midland Basin. As consideration for the acquisition, we paid approximately $595 million in cash. Concurrent with the acquisition, we entered into a transaction structured as a reverse like-kind exchange in accordance with Section 1031 of the Internal Revenue Code of 1986; and

- in September 2017, we issued $1,800 million in aggregate principal amount of unsecured senior notes, consisting of $1,000 million in aggregate principal amount of 3.75% unsecured senior notes due 2027 (the “3.75% Notes”) and $800 million in aggregate principal amount of 4.875% unsecured senior notes due 2047 (the “4.875% Notes” and, together with the 3.75% Notes, the “2017 Notes”). We used the net proceeds of approximately $1,777 million, together with cash on hand and borrowings under our credit facility, to fund the cash tender offer (the “Tender Offer”) and the satisfaction and discharge of the outstanding $600 million aggregate principal amount of our 5.5% unsecured senior notes due 2022 and the outstanding $1,550 million aggregate principal amount of our 5.5% unsecured senior notes due 2023 (collectively, the “5.5% Notes”). As a result of these transactions, we recorded a loss on extinguishment of debt related to the 5.5% Notes of approximately $65 million.

Our financial data below is derived from (i) our audited consolidated financial statements included in this report and (ii) other audited consolidated financial statements of ours not included in this report.

	Years Ended December 31,				
(in millions, except per share amounts)	**2017 (a)**	**2016 (a) (b)**	**2015 (a)**	**2014**	**2013**
Statement of operations data:					
Total operating revenues	$ 2,586	$ 1,635	$ 1,804	$ 2,660	$ 2,320
Total operating costs and expenses	(1,512)	(3,704)	(1,477)	(1,580)	(1,704)
Income (loss) from operations	$ 1,074	$ (2,069)	$ 327	$ 1,080	$ 616
Income (loss) from continuing operations, net of tax	$ 956	$ (1,462)	$ 66	$ 538	$ 239
Income from discontinued operations, net of tax	-	-	-	-	12
Net income (loss) attributable to common shareholders	$ 956	$ (1,462)	$ 66	$ 538	$ 251
Basic earnings per share:					
Income (loss) from continuing operations	$ 6.44	$ (10.85)	$ 0.54	$ 4.89	$ 2.28
Income from discontinued operations, net of tax	-	-	-	-	0.11
Net income (loss) attributable to common shareholders	$ 6.44	$ (10.85)	$ 0.54	$ 4.89	$ 2.39
Diluted earnings per share:					
Income (loss) from continuing operations	$ 6.41	$ (10.85)	$ 0.54	$ 4.88	$ 2.28
Income from discontinued operations, net of tax	-	-	-	-	0.11
Net income (loss) attributable to common shareholders	$ 6.41	$ (10.85)	$ 0.54	$ 4.88	$ 2.39
Other financial data:					
Net cash provided by operations	$ 1,695	$ 1,384	$ 1,530	$ 1,746	$ 1,330
Net cash used in investing activities	$ 1,719	$ 2,225	$ 2,602	$ 2,618	$ 1,864
Net cash provided by (used in) financing activities	$ (29)	$ 665	$ 1,301	$ 872	$ 532
EBITDAX (c)	$ 1,893	$ 1,633	$ 1,713	$ 2,033	$ 1,686

(in millions)	December 31, 2017 (a)	2016 (a) (b)	2015 (a)	2014	2013
Balance sheet data:					
Cash and cash equivalents	$ -	$ 53	$ 229	$ -	$ -
Property and equipment, net	13,041	11,302	10,976	10,206	8,946
Total assets	13,732	12,119	12,642	11,752	9,508
Long-term debt, including current maturities	2,691	2,741	3,332	3,469	3,577
Stockholders' equity	8,915	7,623	6,943	5,281	3,758

(a) See Note 4 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a summary of acquisitions, divestitures and nonmonetary transactions included in our financial data for the selected years.

(b) A non-cash impairment charge of approximately $1.5 billion is included in income (loss) from operations for the year ended December 31, 2016.

(c) EBITDAX is defined as net income (loss), plus (1) exploration and abandonments, (2) depreciation, depletion and amortization, (3) accretion of discount on asset retirement obligations, (4) impairments of long-lived assets, (5) non-cash stock-based compensation, (6) (gain) loss on derivatives, (7) net cash receipts from (payments on) derivatives, (8) (gain) loss on disposition of assets, net, (9) interest expense, (10) loss on extinguishment of debt, (11) federal and state income tax expense (benefit) from continuing operations and (12) similar items listed above that are presented in discontinued operations. See "Item 1. Business —Non-GAAP Financial Measures and Reconciliations."

Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our historical consolidated financial statements and notes, as well as the selected historical consolidated financial data included elsewhere in this report.

Certain statements in our discussion below are forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause actual results to differ materially from those implied or expressed by the forward-looking statements. Please see “Cautionary Statement Regarding Forward-Looking Statements” and “Item 1A. Risk Factors” for further details about these statements.

Overview

We are an independent oil and natural gas company engaged in the acquisition, development, exploration and production of oil and natural gas properties. Our core operations are primarily focused in the Permian Basin of southeast New Mexico and west Texas. Concho’s legacy in the Permian Basin provides us a deep understanding of operating and geological trends. We are actively developing our resource base by utilizing extended length lateral drilling, enhanced completion techniques, multi-well pad locations and large-scale development projects throughout our four core operating areas: the Northern Delaware Basin, the Southern Delaware Basin, the Midland Basin and the New Mexico Shelf. Oil comprised 60 percent of our 840 MMBoe of estimated proved reserves at December 31, 2017 and 62 percent of our 70 MMBoe of production for 2017. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 92 percent of our proved developed producing reserves and 79 percent of our 8,152 gross wells at December 31, 2017. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and stimulation methods used.

Financial and Operating Performance

Our financial and operating performance for 2017 included the following highlights:

- Net income was $956 million ($6.41 per diluted share) as compared to a net loss of $1.5 billion ($(10.85) per diluted share) in 2016. The increase was primarily due to:

- no recorded impairments of long-lived assets in 2017, as compared to $1.5 billion in non-cash impairment charges in 2016 primarily attributable to properties in our New Mexico Shelf area;

- $951 million increase in oil and natural gas revenues as a result of a 28 percent increase in production and a 24 percent increase in commodity price realizations per Boe (excluding the effects of derivative activities);

- $560 million increase in gain on disposition of assets, net due to a gain of approximately $678 million during 2017 primarily attributable to our disposition of ACC, as compared to a gain of approximately $118 million during 2016 primarily attributable to our Northern Delaware Basin divestiture in February 2016;

- $243 million decrease in the loss on derivatives; and

- $21 million decrease in depreciation, depletion and amortization expense, primarily due to a decrease in the depletion rate per Boe, partially offset by an increase in production;

partially offset by:

- $801 million change in our income tax provision primarily due to favorable impacts of the tax law changes enacted through the TCJA, resulting in a provisional discrete income tax benefit of approximately $398 million. This benefit more than offset the $308 million income tax expense on income before taxes during 2017 at the federal statutory rate;

• $88 million increase in production expense, primarily due to (i) increased production associated with our wells successfully drilled and completed in 2016 and 2017 and (ii) our acquisitions during the fourth quarter of 2016 and during 2017; and

• $68 million increase in production and ad valorem tax expense, primarily due to increased production taxes as a result of increased oil and natural gas sales.

• Average daily sales volumes increased by 28 percent from 150,511 Boe per day during 2016 to 192,658 Boe per day during 2017.

• Net cash provided by operating activities increased by approximately $311 million to $1,695 million for 2017, as compared to $1,384 million in 2016, primarily due to increased oil and natural gas revenues and decreased cash interest expense, partially offset by (i) decreased cash settlements on derivatives, (ii) increased production expense and (iii) increased production tax expense.

• Cash decreased by approximately $53 million during 2017 primarily as a result of cash paid to tender and extinguish the 5.5% Notes and cash paid for the Midland Basin and Northern Delaware Basin acquisitions, partially offset by proceeds from the issuance of the 2017 Notes and proceeds from our February 2017 divestiture of ACC.

Commodity Prices

Our results of operations are heavily influenced by commodity prices. See "Item 1A. Risk Factors" for a description of the factors that may impact future commodity prices, including the price of oil, natural gas and natural gas liquids.

Although we cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production. From time to time, we expect that we may economically hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Notes 8 and 17 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our commodity derivative positions at December 31, 2017 and additional derivative contracts entered into subsequent to December 31, 2017, respectively.

Oil and natural gas prices have been subject to significant fluctuations during the past several years. The average oil and natural gas prices were higher during 2017 compared to 2016. The following table sets forth the average NYMEX oil and natural gas prices for the years ended December 31, 2017, 2016 and 2015, as well as the high and low NYMEX prices for the same periods:

	Years Ended December 31,		
	2017	**2016**	**2015**
Average NYMEX prices:			
Oil (Bbl)	$ 50.97	$ 43.42	$ 48.84
Natural gas (MMBtu)	$ 3.02	$ 2.56	$ 2.63
High and Low NYMEX prices:			
Oil (Bbl):			
High	$ 60.42	$ 54.06	$ 61.43
Low	$ 42.53	$ 26.21	$ 34.73
Natural gas (MMBtu):			
High	$ 3.72	$ 3.93	$ 3.23
Low	$ 2.56	$ 1.64	$ 1.76

Further, the NYMEX oil price and NYMEX natural gas price reached highs and lows of $66.14 and $59.19 per Bbl and $3.63 and $2.55 per MMBtu, respectively, during the period from January 1, 2018 to February

16, 2018. At February 16, 2018, the NYMEX oil price and NYMEX natural gas price were $61.68 per Bbl and $2.56 per MMBtu, respectively.

Historically, and during the year ended December 31, 2017, we derived a significant portion of our total natural gas revenues from the value of the natural gas liquids contained in our natural gas, with the remaining portion coming from the value of the dry natural gas residue. The average Mont Belvieu price for a blended barrel of natural gas liquids was $25.06 per Bbl and $18.08 per Bbl during the years ended December 31, 2017 and 2016, respectively.

Potential cost inflation. Oilfield service and supply costs are also subject to supply and demand dynamics. As companies have expanded their drilling and development activities during 2017, the demand for third-party oilfield services and suppliers has also increased. As such, if the commodity price environment continues to trend upward, we expect demand for oilfield services and supplies to continue to grow, and the costs of drilling, equipping and operating our wells and infrastructure could begin to rise.

Recent Events

2018 capital budget. In February 2018, we announced our 2018 capital budget, excluding acquisitions, of approximately $2.0 billion with expected capital spending to range between $1.9 billion and $2.1 billion. Approximately 93 percent of capital will be directed to drilling and completion activity. Our 2018 capital program is expected to continue focusing on large-scale project development. Our 2018 capital budget, based on our current expectations of commodity prices and costs, is expected to be within our cash flows. Our budget could change depending on numerous factors, including commodity prices, leverage metrics and industry conditions.

Tax reform. On December 22, 2017, the President of the United States ("the President") signed into law the TCJA, significantly changing corporate income tax laws. According to Accounting Standards Codification ("ASC") section 740, "Income Taxes," a company is required to record the effects of an enacted tax law or rate change in income from continuing operations in the period of enactment, which is the date the bill is signed by the President and becomes law. We note that certain aspects of these changes will impact our future after-tax earnings primarily due to the lower federal statutory tax rate. The SEC issued Staff Accounting Bulletin No. 118 "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" ("SAB 118") to provide guidance for companies that have not completed the accounting for the income tax effects of the TCJA in the period of enactment. SAB 118 allows companies to report provisional amounts when based on reasonable estimates and to adjust these amounts during a measurement period of up to one year.

Although we have performed an initial assessment of the TCJA, we recognize that it is a comprehensive bill and the ultimate impacts may differ from our initial estimates due to changes in our interpretations as a result of additional regulatory guidance that may become available. As such, we have elected to apply SAB 118 and have recorded, based on reasonable estimates, provisional amounts of our income tax balances reported in our financial statements. See Note 11 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our income tax balances.

As we continue to refine our analysis of the tax law changes and monitor new tax law interpretation, any adjustments to our provisional amounts identified during the measurement period will be included as an adjustment to tax expense or benefit from continuing operations in the period these amounts are determined.

Southern Delaware Basin divestitures. In January 2018, we closed on two asset sales transactions of certain non-core assets in Reeves and Ward Counties with combined preliminary proceeds of approximately $280 million, subject to customary post-closing adjustments. As of December 31, 2017, we received cash deposits totaling approximately $29 million for the asset sales, which was included in the total cash flows from investing activities in our consolidated statement of cash flows. See Note 17 of the

Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding these divestitures.

February 2018 nonmonetary transaction. In February 2018, we closed on a strategic trade where we received approximately 21,000 net acres, primarily located in the Midland Basin, with current production of 5 MBoepd in exchange for 34,000 net acres, primarily comprised of approximately 32,000 net acres in the northern Delaware Basin, with current production of 3 MBoepd.

Derivative Financial Instruments

Derivative financial instrument exposure. At December 31, 2017, the fair value of our financial derivatives was a net liability of $379 million. Under the terms of our financial derivative instruments, we do not have exposure to potential "margin calls" on our financial derivative instruments. The terms of our credit facility do not allow us to offset amounts we may owe a lender against amounts we may be owed related to our financial instruments with such party. In September 2017, we elected to enter into an "Investment Grade Period" under our credit facility, which had the effect of releasing all collateral formerly securing the credit facility and derivative obligations. See Notes 9 and 12 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

New commodity derivative contracts. After December 31, 2017, we entered into the following oil price swaps, oil basis swaps and natural gas price swaps to hedge additional amounts of our estimated future production:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Price Swaps: (a)					
2018:					
Volume (Bbl)	915,000	1,213,000	1,013,000	674,000	3,815,000
Price per Bbl	$ 63.64	$ 63.48	$ 63.34	$ 63.11	$ 63.42
2019:					
Volume (Bbl)	876,000	748,000	636,000	552,000	2,812,000
Price per Bbl	$ 58.14	$ 58.12	$ 58.10	$ 58.08	$ 58.11
2020:					
Volume (Bbl)	1,001,000	1,001,000	1,012,000	1,012,000	4,026,000
Price per Bbl	$ 54.80	$ 54.80	$ 54.80	$ 54.80	$ 54.80
Oil Basis Swaps: (b)					
2018:					
Volume (Bbl)	615,000	637,000	399,000	306,000	1,957,000
Price per Bbl	$ 0.13	$ 0.06	$ (0.07)	$ (0.10)	$ 0.03
2019:					
Volume (Bbl)	180,000	182,000	184,000	-	546,000
Price per Bbl	$ (0.27)	$ (0.27)	$ (0.27)	$ -	$ (0.27)
2020:					
Volume (Bbl)	2,184,000	2,184,000	2,208,000	2,208,000	8,784,000
Price per Bbl	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)	$ (0.09)
Natural Gas Price Swaps: (c)					
2018:					
	1,277,000	878,000	921,000	274,000	3,350,000

Volume (MMBtu)										
Price per MMBtu	$	3.08	$	3.08	$	3.08	$	3.08	$	3.08

(a) The index prices for the oil price swaps are based on the NYMEX – WTI monthly average futures price.
(b) The basis differential price is between Midland – WTI and Cushing – WTI.
(c) The index prices for the natural gas price swaps are based on the NYMEX – Henry Hub last trading day futures price.

Results of Operations

The following table sets forth summary information concerning our production and operating data for the years ended December 31, 2017, 2016 and 2015. The actual historical data in this table excludes results from the Reliance Acquisition for periods prior to October 2016. Because of normal production declines, increased or decreased drilling activities, fluctuations in commodity prices and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Years Ended December 31, 2017	2016	2015
Production and operating data:			
Net production volumes:			
Oil (MBbl)	43,472	33,840	34,457
Natural gas (MMcf)	161,089	127,481	106,987
Total (MBoe)	70,320	55,087	52,288
Average daily production volumes:			
Oil (Bbl)	119,101	92,459	94,403
Natural gas (Mcf)	441,340	348,309	293,115
Total (Boe)	192,658	150,511	143,256
Average prices per unit:			
Oil, without derivatives (Bbl)	$ 48.13	$ 39.90	$ 44.69
Oil, with derivatives (Bbl) (a)	$ 49.93	$ 57.90	$ 62.03
Natural gas, without derivatives (Mcf)	$ 3.07	$ 2.23	$ 2.46
Natural gas, with derivatives (Mcf) (a)	$ 3.06	$ 2.36	$ 2.80
Total, without derivatives (Boe)	$ 36.78	$ 29.68	$ 34.49
Total, with derivatives (Boe) (a)	$ 37.88	$ 41.03	$ 46.60
Operating costs and expenses per Boe: (b)			
Oil and natural gas production	$ 5.80	$ 5.81	$ 7.46
Production and ad valorem taxes	$ 2.82	$ 2.38	$ 2.90
Depreciation, depletion and amortization	$ 16.29	$ 21.19	$ 23.40
General and administrative	$ 3.46	$ 4.09	$ 4.42

(a) Includes the effect of net cash receipts from derivatives:

Years Ended December 31,

(in millions)	2017	2016	2015
Net cash receipts from derivatives:			
Oil derivatives	$ 79	$ 609	$ 597
Natural gas derivatives	-	16	36
Total	$ 79	$ 625	$ 633

The presentation of average prices with derivatives is a result of including the net cash receipts from commodity derivatives that are presented in our statements of cash flows. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

(b) Per Boe amounts calculated using dollars and volumes rounded to thousands.

The following table presents selected production data for the fields which represent greater than 15 percent of our total proved reserves at December 31, 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	**2016**	**2015**
Production:			
South Basin Wolfcamp Bone Spring:			
Oil (MMBbl)	12	11	10
Natural gas (Bcf)	75	56	37
Total (MMBoe)	25	20	16
Midland Basin Spraberry-Wolfcamp:			
Oil (MMBbl)	8	6	(a)
Natural gas (Bcf)	26	20	(a)
Total (MMBoe)	12	9	(a)
Yeso:			
Oil (MMBbl)	7	7	7
Natural gas (Bcf)	28	27	27
Total (MMBoe)	12	12	12

(a) Represented less than 15% of the Company's total proved reserves for the year indicated.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Oil and natural gas revenues. Revenue from oil and natural gas operations was $2,586 million for the year ended December 31, 2017, an increase of $951 million (58 percent) from $1,635 million for 2016. This increase was primarily due to the increase in realized oil and natural gas production as well as the increase in oil and natural gas prices (excluding the effects of derivative activities). Specific factors affecting oil and natural gas revenues include the following:

- total oil production was 43,472 MBbl for the year ended December 31, 2017, an increase of 9,632 MBbl (28 percent) from 33,840 MBbl for 2016;

- average realized oil price (excluding the effects of derivative activities) was $48.13 per Bbl during the year ended December 31, 2017, an increase of 21 percent from $39.90 per Bbl during 2016. For the year ended December 31, 2017, our crude oil price differential relative to NYMEX was $(2.84) per Bbl, or a realization of approximately 94 percent, as compared to a crude oil price differential relative to NYMEX of $(3.52) per Bbl, or a realization of approximately 92 percent, for 2016. The basis differential between the location of Midland, Texas and Cushing, Oklahoma (NYMEX pricing location) for our oil directly impacts our realized oil price. For the year ended December 31, 2017 and 2016, the average market basis differential between WTI-Midland and WTI-Cushing was a price reduction of $0.30 per Bbl and $0.15 per Bbl, respectively. Additionally, we incur fixed deductions from the posted Midland oil price based on the location of our oil within the Permian Basin. These fixed deductions were less per Boe during the year ended December 31, 2017 as compared to 2016 primarily due to more production transported through pipelines and successful renegotiation of fixed deductions for trucked volumes;

- total natural gas production was 161,089 MMcf for the year ended December 31, 2017, an increase of 33,608 MMcf (26 percent) from 127,481 MMcf for 2016; and

- average realized natural gas price (excluding the effects of derivative activities) was $3.07 per Mcf during the year ended December 31, 2017, an increase of 38 percent from $2.23 per Mcf during 2016. For the years ended December 31, 2017 and 2016, we realized approximately 102 percent and 87 percent, respectively, of the average NYMEX natural gas prices for the respective periods. The increase in our realized natural gas price (excluding the effects of derivatives) as a percentage of NYMEX during the year ended December 31, 2017 as compared to 2016 was primarily due to an increase in the average Mont Belvieu price for a blended barrel of natural gas liquids. Historically, and during the year ended December 31, 2017, we derived a significant portion of our total natural gas revenues from the value of the natural gas liquids contained in our natural gas, with the remaining portion coming from the value of the dry natural gas residue. The average Mont Belvieu price for a blended barrel of natural gas liquids was $25.06 per Bbl and $18.08 per Bbl during the years ended December 31, 2017 and 2016, respectively.

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Oil and natural gas production expenses. The following table provides the components of our oil and natural gas production expenses for the years ended December 31, 2017 and 2016:

	Years Ended December 31,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 387	$ 5.50	$ 301	$ 5.46
Workover costs	21	0.30	19	0.35
Total oil and natural gas production expenses	$ 408	$ 5.80	$ 320	$ 5.81

Lease operating expenses were $387 million ($5.50 per Boe) for the year ended December 31, 2017, which was an increase of $86 million (29 percent) from $301 million ($5.46 per Boe) for the year ended December 31, 2016. The increase in lease operating expenses was primarily due to (i) increased production associated with our wells successfully drilled and completed in 2016 and 2017, (ii) our acquisitions during the fourth quarter of 2016 and during 2017, particularly our Reliance Acquisition and our Midland Basin acquisition, whose associated properties incur higher lease operating expense per Boe than our legacy assets and (iii) increased cost of services.

Production and ad valorem taxes. The following table provides the components of our production and ad valorem tax expenses for the years ended December 31, 2017 and 2016:

	Years Ended December 31,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Production taxes	$ 181	$ 2.58	$ 117	$ 2.13
Ad valorem taxes	18	0.24	14	0.25
Total production and ad valorem taxes	$ 199	$ 2.82	$ 131	$ 2.38

Production taxes per unit of production were $2.58 per Boe during the year ended December 31, 2017, an increase of 21 percent from $2.13 per Boe during 2016. Over the same period, our revenue per Boe (excluding the effects of derivatives) increased 24 percent. The increase in production taxes per unit of production was directly related to the increase in oil and natural gas sales, partially offset by a $5 million tax credit received during 2017 related to certain wells in Texas qualifying for reduced severance tax rates, as compared to $4 million in tax credit received during 2016. Production taxes fluctuate with the market value of our production sold, while ad valorem taxes are generally based on the valuation of our oil and natural gas properties at the beginning of the year, which vary across the different areas in which we operate.

Exploration and abandonments expense. The following table provides the components of our exploration and abandonments expense for the years ended December 31, 2017 and 2016:

(in millions)	**Years Ended December 31, 2017**	**2016**
Geological and geophysical	$ 13	$ 8
Exploratory dry hole costs	-	7
Leasehold abandonments	27	50
Other	19	12
Total exploration and abandonments	$ 59	$ 77

Our geological and geophysical expense for the periods presented above primarily consists of the costs of acquiring and processing geophysical data and core analysis.

Our exploratory dry hole costs during the year ended December 31, 2016 were primarily related to an uneconomic well in our Northern Delaware Basin core area that was attempting to establish commercial production through testing of multiple zones. We did not recognize any exploratory dry hole costs during the year ended December 31, 2017.

For the years ended December 31, 2017 and 2016, we recorded approximately $29 million and $60 million, respectively, of leasehold abandonments. For the year ended December 31, 2017, our abandonments were primarily related to (i) acreage expiring in our Southern Delaware Basin core area and (ii) acreage in our Northern Delaware Basin and New Mexico Shelf core areas in locations where we have no future plans to drill. For the year ended December 31, 2016, our abandonments were primarily related to (i) drilling locations in our Northern Delaware Basin and New Mexico Shelf core areas that, based on multiple factors, are no longer likely to be drilled, (ii) acreage in our Northern Delaware Basin and New Mexico Shelf core areas where we have no future development plans and (iii) expiring acreage primarily located in our Northern Delaware Basin and Southern Delaware Basin areas.

Our other expense for the periods presented above primarily consists of surface and title costs on locations we no longer intend to drill, certain plugging costs and delay rentals.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the years ended December 31, 2017 and 2016:

	Years Ended December 31,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Depletion of proved oil and natural gas properties	$ 1,122	$ 15.95	$ 1,145	$ 20.79
Depreciation of other property and equipment	21	0.29	21	0.37
Amortization of intangible assets	3	0.05	1	0.03
Total depletion, depreciation and amortization	$ 1,146	$ 16.29	$ 1,167	$ 21.19
Oil price used to estimate proved oil reserves at period end	$ 47.79		$ 39.25	
Natural gas price used to estimate proved natural gas reserves at period end	$ 2.98		$ 2.48	

Depletion of proved oil and natural gas properties was $1,122 million ($15.95 per Boe) for the year ended December 31, 2017, a decrease of $23 million (2 percent) from $1,145 million ($20.79 per Boe) for 2016. The decrease in depletion expense was primarily due to a lower depletion rate per Boe partially offset by an increase in production. The decrease in depletion expense per Boe was primarily due to (i) lower drilling and completion costs per Boe of proved developed reserves added, (ii) an overall increase in proved reserves primarily caused by our successful exploratory drilling program, the Reliance Acquisition as well as other acquisitions, and higher commodity prices, partially offset by decreased proved reserves caused by reclassification of proved undeveloped reserves to unproved reserves because they are no longer expected to be developed within five years of the date of their initial recognition and (iii) a non-cash impairment charge of approximately $1.5 billion recorded in the first quarter of 2016.

Impairments of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties and their integrated assets, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. We review our oil and natural gas properties by depletion base. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of our assets, we recognize an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

We estimate undiscounted future net cash flows of our long-lived assets and their integrated assets using management's assumptions and expectations of (i) commodity prices, which are based on the NYMEX strip, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves and (vii) prevailing market rates of income and expenses from integrated assets. At December 31, 2017, our estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2018 price of $59.55 per barrel of oil decreasing to a 2024 price of $51.82 per barrel of oil marginally recovering to a 2025 price of $51.83 per barrel of oil. Similarly, natural gas prices ranged from a 2018 price of $2.84 per Mcf of natural gas decreasing to a 2019 price of $2.81 per Mcf then rising to a 2025 price of $2.99 per Mcf of natural gas. Both oil and natural gas commodity prices for this purpose were held flat after 2025.

We estimate fair values of our long-lived assets and their integrated assets using a discounted future cash flow model. Fair value assumptions associated with the calculation of discounted future net cash flows include (i) market estimates of commodity prices, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, (vii) prevailing market rates of income and expenses from integrated assets and (viii) discount rate. The expected future net cash flows were discounted using an annual rate of 10 percent to determine fair value.

During the three months ended March 31, 2016, NYMEX strip prices declined as compared to December 31, 2015, and as a result the carrying amount of our Yeso field in our New Mexico Shelf core area exceeded the expected undiscounted future net cash flows resulting in a non-cash charge against earnings of approximately $1.5 billion. The Yeso field, as compared to our other fields not previously impaired, had significant proved reserves upon acquisition, which required a higher valuation than a field more exploratory in nature that has a higher risk factor adjustment in the fair value estimate. Our estimates of commodity prices for purposes of determining the estimated fair value at March 31, 2016 ranged from a 2016 price of $41.26 per barrel of oil and $2.26 per Mcf of natural gas to a 2023 price of $66.33 per barrel of oil and $3.56 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2023. We did not recognize an impairment charge during the year ended December 31, 2017.

It is reasonably possible that the estimate of undiscounted future net cash flows of our long-lived assets may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future net cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities and (v) prevailing market rates of income and expenses from integrated assets.

We estimate that if the future oil and natural gas prices used in this analysis, and noted above, would have been approximately 10 percent lower at December 31, 2017 with no other changes in capital costs, operating costs, price differentials, or reserve performance curves, no impairment would be indicated. Other assumptions such as operating costs, well and reservoir performance, severance and ad valorem taxes, and operating and development plans would likely change given a change in oil and natural gas prices. However, we did not estimate the correlation between these assumptions and any estimated commodity price change, and these and other assumptions may worsen or partially mitigate some of the effects of a reduction in commodity prices, including the ultimate impact and amount of any potential impairment charge. As a result, we are unable to predict with certainty whether or not a decline in commodity prices alone will or will not cause us to recognize an impairment charge in a particular field or the magnitude of any such impairment charge. We additionally note that there may be changes to both drilling and completion designs that affect the volume curves, capital costs estimates, and the amount of proved undeveloped locations that can be recorded, each of which will affect management’s estimates of future cash flows.

General and administrative expenses. The following table provides components of our general and administrative expenses for the years ended December 31, 2017 and 2016:

	Years Ended December 31,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses	$ 200	$ 2.85	$ 184	$ 3.33
Less: Operating fee reimbursements	(16)	(0.24)	(17)	(0.31)
Non-cash stock-based compensation	60	0.85	59	1.07
Total general and administrative expenses	$ 244	$ 3.46	$ 226	$ 4.09

General and administrative expenses were approximately $244 million ($3.46 per Boe) for the year ended December 31, 2017, an increase of $18 million (8 percent) from $226 million ($4.09 per Boe) for 2016. The increase in cash general and administrative expenses was primarily a result of increased compensation expense. The decrease in total general and administrative expenses per Boe was primarily due to increased production, partially offset by the increase in cash general and administrative costs noted above.

We receive fees for the operation of jointly-owned oil and natural gas properties during the drilling and production phases and record such reimbursements as reductions of general and administrative expenses in the consolidated statements of operations. We earned reimbursements of approximately $16 million and $17 million during the years ended December 31, 2017 and 2016, respectively.

Gain (loss) on derivatives. The following table sets forth the gain (loss) on derivatives for the years ended December 31, 2017 and 2016:

	Years Ended December 31,	
(in millions)	**2017**	**2016**
Gain (loss) on derivatives:		
Oil derivatives	$ (172)	$ (337)
Natural gas derivatives	46	(32)
Total	$ (126)	$ (369)

The following table represents our net cash receipts from derivatives for the years ended December 31, 2017 and 2016:

(in millions)	Years Ended December 31, 2017	2016
Net cash receipts from derivatives:		
Oil derivatives	$ 79	$ 609
Natural gas derivatives	-	16
Total	$ 79	$ 625

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which could be significant. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains; while to the extent future commodity price outlook increases between measurement periods, we will have mark-to-market losses. See Note 7 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding significant judgments made in classifying financial instruments in the fair value hierarchy.

Gain on disposition of assets, net. During the years ended December 31, 2017 and 2016, we recognized a gain on disposition of assets of approximately $678 million and $118 million, respectively. In February 2017, we closed on the divestiture of our ownership interest in ACC. After adjustments for debt and working capital, we received cash proceeds from the sale of approximately $801 million. After direct transaction costs, we recorded a pre-tax gain on disposition of assets of approximately $655 million. Our net investment in ACC at the time of closing was approximately $129 million. In February 2016, we sold certain assets in our Northern Delaware Basin core area for proceeds of approximately $292 million and recognized a pre-tax gain of approximately $110 million.

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the years ended December 31, 2017 and 2016:

	Years Ended December 31,			
(in millions)		**2017**		**2016**
Interest expense, as reported	$	146	$	204
Capitalized interest		3		-
Interest expense, excluding impact of capitalized interest	$	149	$	204
Weighted average interest rate – credit facility		3.5%		-
Weighted average interest rate – senior notes		5.0%		5.9%
Total weighted average interest rate		5.0%		5.9%
Weighted average credit facility balance	$	100	$	-
Weighted average senior notes balance		2,658		3,182
Total weighted average debt balance	$	2,758	$	3,182

Our weighted average debt balance decreased for the year ended December 31, 2017 as compared to 2016 primarily due to (i) the satisfaction and discharge of the 6.5% Notes in December 2016, (ii) the redemption of the 7.0% Notes in September 2016 and (iii) the satisfaction and discharge of the 5.5% Notes in September 2017, partially offset by (i) the issuance of the 4.375% Notes in December 2016, (ii) the issuance of the 2017 Notes in September 2017 and (iii) an increase in borrowings under our credit facility. The decrease in interest expense was due to the overall decrease in the weighted average debt balance and an increase in capitalized interest.

Loss on extinguishment of debt. We recorded a loss on extinguishment of debt of $66 million for the year ended December 31, 2017. This amount includes: (i) approximately $36 million associated with the premium paid for the Tender Offer, approximately $25 million associated with the make-whole premium paid for the early extinguishment of the 5.5% Notes, approximately $21 million of unamortized deferred loan costs and approximately $2 million of additional interest on the 5.5% Notes to October 13, 2017, which was paid in September 2017, reduced by approximately $19 million of unamortized premium; and (ii) approximately $1 million representing the proportional amount of unamortized deferred loan costs associated with banks that are no longer in the credit facility syndicate as a result of the April 2017 credit facility amendment.

We recorded a loss on extinguishment of debt of $56 million for the year ended December 31, 2016. This amount includes: (i) approximately $20 million associated with the make-whole premium paid for the early extinguishment of the 6.5% Notes in December 2016, approximately $7 million of related unamortized deferred loan costs and approximately $1 million of additional interest on the 6.5% Notes through January 16, 2017, which was paid in December 2016; and (ii) $21 million associated with the make-whole premium paid for the early redemption of the 7.0% Notes in September 2016 and approximately $7 million of related unamortized deferred loan costs.

Income tax provisions. For the year ended December 31, 2017, we recorded an income tax benefit of $75 million, which includes discrete provisional income tax benefits of approximately $398 million related to the enactment of the TCJA and $6 million related to stock-based awards recorded in the income tax provision pursuant to ASU No. 2016-09 adopted on January 1, 2017. For the year ended December 31, 2016, we recorded an income tax benefit of $876 million primarily due to having a loss before income taxes.

The change in our income tax provision in 2017 as compared to 2016 was primarily due to the favorable impacts of the tax law changes enacted through the TCJA in December 2017 as the income tax benefit related to the federal statutory rate change more than offset our income tax expense of $308 million on income before income taxes during 2017. The effective income tax rates for the years ended December 31, 2017 and 2016 were (9) percent and 38 percent, respectively. The 2017 rate was negative due to recognizing an overall income tax benefit while having pre-tax income.

As we continue to implement and address the ongoing impacts of the TCJA, we may determine it necessary in the future to adjust our income tax calculations due to changes in our initial interpretations or assumptions. As we have elected to apply

SAB 118, adjustments to provisional amounts included in the total income tax benefit are allowable during the one-year measurement period. We will continue to monitor new tax law interpretations.

We evaluate changes to our industry, production, market conditions and changes in our forecasted drilling plan by tax jurisdiction. Our material state tax jurisdictions include Texas and New Mexico. In February 2017, we sold our ownership interest in ACC, which consisted of property in both Texas and New Mexico, and in April 2017, we completed an acquisition of assets in the Northern Delaware Basin. We have considered these and other factors and did not identify a shift in our projected future apportionment between New Mexico and Texas for the year ended December 31, 2017. In October 2016, we purchased Texas-based assets in the Reliance Acquisition for approximately $1.7 billion, which caused a shift in our projected future apportionment from New Mexico to Texas, which has a lower statutory state tax rate than New Mexico. As such, we recognized an overall state deferred tax benefit of approximately $21 million for the year ended December 31, 2016.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Oil and natural gas revenues. Revenue from oil and natural gas operations was $1,635 million for the year ended December 31, 2016, a decrease of $169 million (9 percent) from $1,804 million for 2015. This decrease was primarily due to the decrease in realized oil and natural gas prices partially offset by an increase in natural gas production. Specific factors affecting oil and natural gas revenues include the following:

- total oil production was 33,840 MBbl for the year ended December 31, 2016, a decrease of 617 MBbl (2 percent) from 34,457 MBbl for 2015;

- average realized oil price (excluding the effects of derivative activities) was $39.90 per Bbl during the year ended December 31, 2016, a decrease of 11 percent from $44.69 per Bbl during 2015. For the year ended December 31, 2016, our crude oil price differential relative to NYMEX was $(3.52) per Bbl, or a realization of approximately 92 percent, as compared to a crude oil price differential relative to NYMEX of $(4.15) per Bbl, or a realization of approximately 92 percent, for 2015. We incur fixed deductions from the posted Midland oil price based on the location of our oil within the Permian Basin. Additionally, the basis differential between the location of Midland, Texas and Cushing, Oklahoma (NYMEX pricing location) for our oil directly impacts our realized oil price. For the years ended December 31, 2016 and 2015, the average market basis differential between WTI-Midland and WTI-Cushing was a price reduction of $0.15 per Bbl and $0.41 per Bbl, respectively;

- total natural gas production was 127,481 MMcf for the year ended December 31, 2016, an increase of 20,494 MMcf (19 percent) from 106,987 MMcf for 2015; and

- average realized natural gas price (excluding the effects of derivative activities) was $2.23 per Mcf during the year ended December 31, 2016, a decrease of 9 percent from $2.46 per Mcf during 2015. For the years ended December 31, 2016 and 2015, we realized approximately 87 percent and 94 percent, respectively, of the average NYMEX natural gas prices for the respective periods. Factors contributing to the decrease in our realized gas price (excluding the effects of derivatives) as a percentage of NYMEX during the year ended December 31, 2016 as compared to 2015 were (i) a decrease in the posted regional natural gas prices on which we are paid while the NYMEX natural gas price decreased at a lesser rate and (ii) increased deductions and fees from the regional natural gas price, comparatively. Over the past three years, approximately half of our total natural gas revenues have been derived from the value of the natural gas liquids contained in our natural gas, with the remaining portion coming from the value of the dry natural gas residue. The average Mont Belvieu price for a blended barrel of natural gas liquids was $18.08 per Bbl and $17.80 per Bbl during the years ended December 31, 2016 and 2015, respectively.

Oil and natural gas production expenses. The following table provides the components of our oil and natural gas production expenses for the years ended December 31, 2016 and 2015:

	Years Ended December 31,			
	2016		2015	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 301	$ 5.46	$ 362	$ 6.93
Workover costs	19	0.35	28	0.53
Total oil and natural gas production expenses	$ 320	$ 5.81	$ 390	$ 7.46

Among the cost components of production expenses, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are related to commodity prices.

Lease operating expenses were $301 million ($5.46 per Boe) for the year ended December 31, 2016, which was a decrease of $61 million (17 percent) from $362 million ($6.93 per Boe) for the year ended December 31, 2015. The decrease in lease operating expenses was primarily due to (i) implementation of operational cost efficiencies and (ii) an overall decrease in the cost of goods and services. The decrease in lease operating expenses per Boe was primarily due to the reduction in lease operating expenses noted above coupled with a slight increase in production.

Workover expenses were approximately $19 million and $28 million for the years ended December 31, 2016 and 2015, respectively. The decrease was primarily related to less overall activity during 2016 as compared to 2015.

Production and ad valorem taxes. The following table provides the components of our production and ad valorem tax expenses for the years ended December 31, 2016 and 2015:

	Years Ended December 31,	
	2016	**2015**

(in millions, except per unit amounts)		Amount		Per Boe		Amount		Per Boe
Production taxes	$	117	$	2.13	$	128	$	2.46
Ad valorem taxes		14		0.25		23		0.44
Total production and ad valorem taxes	$	131	$	2.38	$	151	$	2.90

Production taxes per unit of production were $2.13 per Boe during the year ended December 31, 2016, a decrease of 13 percent from $2.46 per Boe during 2015. The decrease was directly related to the decrease in oil and natural gas prices. Over the same period, our average realized prices per Boe (excluding the effects of derivatives) decreased 14 percent.

Exploration and abandonments expense. The following table provides the components of our exploration and abandonments expense for the years ended December 31, 2016 and 2015:

	Years Ended December 31,	
(in millions)	**2016**	**2015**
Geological and geophysical	$ 8	$ 10
Exploratory dry hole costs	7	9
Leasehold abandonments	50	25
Other	12	15
Total exploration and abandonments	$ 77	$ 59

Our geological and geophysical expense for the periods presented above primarily consists of the costs of acquiring and processing geophysical data and core analysis.

Our exploratory dry hole costs during the year ended December 31, 2016 were primarily related to an uneconomic well in our Northern Delaware Basin core area that was attempting to establish commercial production through testing of multiple zones. Our exploratory dry hole costs during the year ended December 31, 2015 were primarily related to (i) an uneconomic well in our Southern Delaware Basin core area that was attempting to establish production in an unconventional zone for the area and (ii) expensing an unsuccessful well, which we did not operate, that was located in our New Mexico Shelf core area.

During the year ended December 31, 2016, we recognized leasehold abandonment expense of approximately $50 million primarily related to (i) drilling locations in our Northern Delaware Basin and New Mexico Shelf core areas which, based on multiple factors, are no longer likely to be drilled, (ii) acreage in our Northern Delaware Basin and New Mexico Shelf core areas where we have no future development plans and (iii) expiring acreage primarily located in our Northern Delaware Basin and Southern Delaware Basin core areas.

During the year ended December 31, 2015, we recognized leasehold abandonment expense of approximately $25 million primarily related to expired and abandoned acreage in our Northern Delaware Basin core area where we currently have no intent to drill.

Our other expense for the periods presented above primarily consists of surface and title costs on locations we no longer intend to drill, certain plugging costs and delay rentals.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the years ended December 31, 2016 and 2015:

	Years Ended December 31,			
	2016		2015	
(in millions, except per unit amounts)	Amount	Per Boe	Amount	Per Boe
Depletion of proved oil and natural gas properties	$ 1,145	$ 20.79	$ 1,203	$ 23.02
Depreciation of other property and equipment	21	0.37	19	0.35
Amortization of intangible assets	1	0.03	1	0.03
Total depletion, depreciation and amortization	$ 1,167	$ 21.19	$ 1,223	$ 23.40
Oil price used to estimate proved oil reserves at period end	$ 39.25		$ 46.79	
Natural gas price used to estimate proved natural gas reserves at period end	$ 2.48		$ 2.59	

Depletion of proved oil and natural gas properties was $1,145 million ($20.79 per Boe) for the year ended December 31, 2016, a decrease of $58 million (5 percent) from $1,203 million ($23.02 per Boe) for 2015. The decrease in depletion expense was primarily due to a lower depletion rate per Boe partially offset by an increase in production. The decrease in depletion expense per Boe was primarily due to (i) a non-cash impairment charge of approximately $1.5 billion recorded in the first quarter of 2016 and (ii) an overall increase in proved reserves primarily caused by our successful exploratory drilling program, the Reliance Acquisition and reductions in future estimated lease operating expenses, partially offset by decreased proved reserves caused by (i) reclassification of proved undeveloped reserves to unproved reserves because they are no longer expected to be developed within five years of the date of their initial recognition and (ii) lower commodity prices.

The increase in depreciation expense was primarily associated with additional other property and equipment related to buildings and other items.

Impairments of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties and their integrated assets, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. We review our oil and natural gas properties by depletion base. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of our assets, we recognize an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

We calculate the expected undiscounted future net cash flows of our long-lived assets and their integrated assets using management's assumptions and expectations of (i) commodity prices, which are based on the NYMEX strip, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves and (vii) prevailing market rates of income and expenses from integrated assets. At December 31, 2016, our estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2017 price of $56.19 per barrel of oil to a 2024 price of $57.41 per barrel of oil. Similarly, natural gas prices ranged from a 2017 price of $3.61 per Mcf of natural gas decreasing to a 2020 price of $2.88 per Mcf of natural gas partially recovering to a 2024 price of $3.38 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2024.

We calculate the estimated fair values of our long-lived assets and their integrated assets using a discounted future cash flow model. Fair value assumptions associated with the calculation of discounted future net cash flows include (i) market estimates of commodity prices, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, (vii) prevailing market rates of income and expenses from integrated assets and (viii) discount rate. The expected future net cash flows were discounted using an annual rate of 10 percent to determine fair value.

During the three months ended March 31, 2016, NYMEX strip prices declined as compared to December 31, 2015, and as a result the carrying amount of our Yeso field in our New Mexico Shelf core area exceeded the expected undiscounted future net cash flows resulting in a non-cash charge against earnings of approximately $1.5 billion. The Yeso field, as compared to our other fields not previously impaired, had significant proved reserves upon acquisition, which required a higher valuation than a field more exploratory in nature that has a higher risk factor adjustment in the fair value estimate. Our estimates of commodity prices for purposes of determining the estimated fair value at March 31, 2016 ranged from a 2016 price of $41.26 per barrel of oil and $2.26 per Mcf of natural gas to a 2022 price of $66.33 per barrel of oil and $3.56 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2022.

We recognized a non-cash charge against earnings of approximately $61 million for the year ended December 31, 2015 as a result of the carrying amount of certain of our long-lived assets and their integrated assets being less than their expected undiscounted future net cash flows, which was primarily attributable to properties in our eastern Midland Basin area.

It is reasonably possible that the estimate of undiscounted future net cash flows of our long-lived assets may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future net cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities and (v) prevailing market rates of income and expenses from integrated assets. If the oil and natural gas prices used in this analysis would have been approximately 10 percent lower as of December 31, 2016 with no other changes in capital costs, operating costs, price differentials, or reserve volumes, no impairment would be indicated.

General and administrative expenses. The following table provides components of our general and administrative expenses for the years ended December 31, 2016 and 2015:

	Years Ended December 31,			
	2016		2015	
(in millions, except per unit amounts)	Amount	Per Boe	Amount	Per Boe
General and administrative expenses	$ 184	$ 3.33	$ 187	$ 3.58
Less: Operating fee reimbursements	(17)	(0.31)	(19)	(0.37)
Non-cash stock-based compensation	59	1.07	63	1.21
Total general and administrative expenses	$ 226	$ 4.09	$ 231	$ 4.42

General and administrative expenses were approximately $226 million ($4.09 per Boe) for the year ended December 31, 2016, a decrease of $5 million (2 percent) from $231 million ($4.42 per Boe) for 2015. The decrease in non-cash stock-based compensation was primarily due to an increase in forfeiture estimates. The decrease in total general and administrative expenses per Boe was primarily due to the reduction in non-cash stock-based compensation costs noted above coupled with a slight increase in production.

We receive fees for the operation of jointly-owned oil and natural gas properties during the drilling and production phases and record such reimbursements as reductions of general and administrative expenses in the consolidated statements of operations. We earned reimbursements of $17 million and $19 million during the years ended December 31, 2016 and 2015, respectively. The decrease in reimbursements was primarily due to decreased drilling and completion activity during 2016 and a higher average working interest in our wells drilled in 2016 as compared to 2015, partially offset by increased reimbursements attributable to more wells operated in 2016 as compared to 2015.

Gain (loss) on derivatives. The following table sets forth the gain (loss) on derivatives for the years ended December 31, 2016 and 2015:

	Years Ended December 31,	
(in millions)	2016	2015
Gain (loss) on derivatives:		

Oil derivatives	$	(337)	$	675
Natural gas derivatives		(32)		25
Total	$	(369)	$	700

The following table represents our net cash receipts from derivatives for the years ended December 31, 2016 and 2015:

	Years Ended December 31,			
(in millions)		**2016**		**2015**
Net cash receipts from derivatives:				
Oil derivatives	$	609	$	597
Natural gas derivatives		16		36
Total	$	625	$	633

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which could be significant. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains, while to the extent future commodity price outlook increases between measurement periods, we will have mark-to-market losses. See Note 7 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding significant judgments made in classifying financial instruments in the fair value hierarchy.

Gain (loss) on disposition of assets, net. During the years ended December 31, 2016 and 2015, we recognized a gain on disposition of assets of approximately $118 million and a loss on disposition of assets of approximately $54 million, respectively. In February 2016, we sold certain assets in our Northern Delaware Basin core area for proceeds of approximately $292 million and recognized a pre-tax gain of approximately $110 million. In December 2015, we completed an acreage exchange with Clayton Williams Energy, Inc. that consolidated acres into a concentrated, operated position in our Southern Delaware Basin core area. We recognized a loss on disposition of assets of approximately $50 million related to the acreage exchange.

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the years ended December 31, 2016 and 2015:

	Years Ended December 31,	
(dollars in millions)	**2016**	**2015**
Interest expense	$ 204	$ 215
Capitalized interest	-	5
Interest expense, excluding impact of capitalized interest	$ 204	$ 220
Weighted average interest rate - credit facility	-	2.4%
Weighted average interest rate - senior notes	5.9%	5.9%
Total weighted average interest rate	5.8%	5.8%
Weighted average credit facility balance	$ -	$ 195
Weighted average senior notes balance	3,182	3,350
Total weighted average debt balance	$ 3,182	$ 3,545

The decrease in the weighted average debt balance for the year ended December 31, 2016 as compared to 2015 was due to the repayment of our credit facility using a portion of the proceeds from our October

2015 equity offering and, to a lesser extent, the early redemption of the $600 million outstanding principal amount of the 7.0% Notes. The decrease in interest expense was due to the overall decrease in the weighted average debt balance, partially offset by a reduction in capitalized interest.

Loss on extinguishment of debt. We recorded a loss on extinguishment of debt of $56 million for the year ended December 31, 2016. This amount includes (i) approximately $20 million associated with the make-whole premium paid for the early extinguishment of the 6.5% Notes in December 2016, approximately $7 million of related unamortized deferred loan costs and approximately $1 million of additional interest on the 6.5% Notes through January 16, 2017, which was paid in December 2016; and (ii) $21 million associated with the make-whole premium paid for the early redemption of the 7.0% Notes in September 2016 and approximately $7 million of related unamortized deferred loan costs.

Income tax provisions. We recorded an income tax benefit of approximately $876 million and income tax expense of approximately $31 million for the years ended December 31, 2016 and 2015, respectively. The shift in our income tax provision is primarily due to a significant pre-tax book loss in 2016 as compared to pre-tax book income in 2015. The effective income tax rates for the years ended December 31, 2016 and 2015 were 38 percent and 32 percent, respectively.

We evaluate changes to our industry, production, market conditions and changes in our forecasted drilling plan by tax jurisdiction. Our material state tax jurisdictions include Texas and New Mexico. In October 2016, we purchased Texas-based assets in the Reliance Acquisition for approximately $1.7 billion, which caused a shift in our projected future apportionment from New Mexico to Texas, which has a lower statutory state tax rate than New Mexico. As such, we recognized an overall state deferred tax benefit of approximately $21 million and approximately $9 million for 2016 and 2015, respectively.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. Our primary needs for cash are development, exploration and acquisition of oil and natural gas assets, payment of contractual obligations and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, financing under our credit facility, proceeds from the disposition of assets or alternative financing sources, as discussed in "—Capital resources" below.

Oil and natural gas properties. Our costs incurred on oil and natural gas properties, excluding acquisitions, during the years ended December 31, 2017, 2016 and 2015 totaled $1.7 billion, $1.2 billion and $1.8 billion, respectively. The increase from 2016 to 2017 was primarily due to our increased drilling and completion activity level during 2017 as compared to 2016. Our intent is to manage our capital spending to be within our cash flow, excluding unbudgeted acquisitions. The primary reason for the differences in costs incurred and cash flow expenditures was our issuance of approximately 2.2 million shares of common stock related to our Northern Delaware Basin acquisition and timing of payments. Total 2017 expenditures were primarily funded in part from (i) cash flows from operations, (ii) proceeds from our February 2017 divestiture of ACC and (iii) our issuance of approximately 2.2 million shares of common stock related to our Northern Delaware Basin acquisition.

2018 capital budget. In February 2018, we announced our 2018 capital budget, excluding acquisitions, of approximately $2.0 billion with expected capital spending to range between $1.9 billion and $2.1 billion. Our 2018 capital budget, based on our current expectations of commodity prices and costs, is expected to be within our cash flows.

Other than the customary purchase of leasehold acreage, our capital budgets are exclusive of acquisitions. We do not have a specific acquisition budget, since the timing and size of acquisitions are difficult to forecast. We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and natural gas properties that provide opportunities for the addition of reserves and production through a combination of development, high-potential exploration and control of operations that will allow us to apply our operating expertise.

Acquisitions. The following table reflects our expenditures for acquisitions of proved and unproved properties for the years ended December 31, 2017, 2016 and 2015:

Years Ended December 31,

(in millions)		2017		2016		2015
Property acquisition costs:						
Proved	$	303	$	982	$	57
Unproved		905		1,154		206
Total property acquisition costs (a)	$	1,208	$	2,136	$	263

(a) Included in the property acquisition costs above are budgeted unproved leasehold acreage acquisitions of approximately $52 million, $30 million and $69 million for the years ended December 31, 2017, 2016 and 2015, respectively. For the year ended December 31, 2017, our unbudgeted acquisitions are primarily comprised of approximately $1.1 billion of property acquisition costs related to our Midland Basin and Northern Delaware Basin acquisitions. For the year ended December 31, 2016, our unbudgeted acquisitions are primarily comprised of approximately $2.1 billion of property acquisition costs related to the Reliance Acquisition and Southern Delaware Basin acquisition.

Contractual obligations. We had the following contractual obligations at December 31, 2017:

		Payments Due by Period			
(in millions)	**Total**	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**
Long-term debt (a)	$ 2,722	$ -	$ -	$ 322	$ 2,400
Cash interest expense on debt (b)	1,797	150	229	222	1,196
Derivative liabilities (c)	379	277	102	-	-
Asset retirement obligations (d)	141	12	13	3	113
Employment agreements with officers (e)	8	8	-	-	-
Purchase obligations (f)	256	33	84	55	84
Operating lease obligations (g)	31	10	15	5	1
Total contractual obligations	$ 5,334	$ 490	$ 443	$ 607	$ 3,794

(a) See Note 9 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for information regarding future interest payment obligations on our long-term debt. The amounts included in the table above represent principal maturities only.

(b) Cash interest expense on our senior notes is estimated assuming no principal repayment until their maturity dates. Also included in the “Less than 1 year” column is accrued interest at December 31, 2017 of approximately $36 million. During 2017, we decreased our annual interest expense and extended our average maturity from six to 16 years by issuing the 2017 Notes and completing the satisfaction and discharge of the 5.5% Notes. At December 31, 2017, we had variable-rate debt outstanding under our credit facility of $322 million.

(c) Derivative obligations represent commodity derivatives that were valued at December 31, 2017. The ultimate settlement amounts of our derivative obligations are unknown because they are subject to continuing market risk. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” and Note 8 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our derivative obligations.

(d) Amounts represent costs related to expected oil and natural gas property abandonments related to proved reserves by period, net of any future accretion.

(e) Represents amounts of cash compensation we are obligated to pay to our officers under employment agreements assuming such employees continue to serve the entire term of their employment agreement and their cash compensation is not adjusted.

(f) Relates to purchase agreements we have entered into including daywork drilling contracts, water commitment agreements, throughput volume delivery commitments, power commitments, fixed asset commitments and maintenance commitments.

(g) We lease vehicles, equipment and office facilities under non-cancellable operating leases.

Off-balance sheet arrangements. Currently, we do not have any material off-balance sheet arrangements.

Capital resources. Our primary sources of liquidity have been cash flows generated from (i) operating activities, (ii) borrowings under our credit facility, (iii) proceeds from bond and equity offerings and (iv) asset dispositions. In February 2018, we announced our 2018 capital budget, excluding acquisitions, of approximately $2.0 billion with expected capital spending to range between $1.9 billion and $2.1 billion. Our 2018 capital budget, based on our current expectations of commodity prices and costs, is expected to be within our cash flows.

The following table summarizes our net increase (decrease) in cash and cash equivalents for the years ended December 31, 2017, 2016 and 2015:

	Years Ended December 31,		
(in millions)	**2017**	**2016**	**2015**
Net cash provided by operating activities	$ 1,695	$ 1,384	$ 1,530
Net cash used in investing activities	(1,719)	(2,225)	(2,602)
Net cash provided by (used in) financing activities	(29)	665	1,301
Net increase (decrease) in cash and cash equivalents	$ (53)	$ (176)	$ 229

Cash flow from operating activities. The increase in operating cash flows during the year ended December 31, 2017 as compared to 2016 was primarily due to an increase in oil and natural gas revenues of approximately $951 million and a decrease in cash interest expense of approximately $55 million, partially offset by (i) approximately $546 million decrease in settlements received from derivatives, (ii) approximately $88 million increase in production expense and (iii) approximately $68 million increase in production tax expense.

The decrease in operating cash flows during the year ended December 31, 2016 as compared to 2015 was primarily due to a decrease in oil and natural gas revenues of approximately $169 million and approximately $95 million of negative variances in operating assets and liabilities, partially offset by (i) approximately $70 million decrease in production expense, (ii) approximately $20 million decrease in production tax expense, (iii) an increase in operating cash flow of approximately $13 million due to a cash tax benefit of approximately $12 million for the year ended December 31, 2016 compared to cash tax expense of approximately $1 million during 2015 and (iv) a decrease in cash interest expense of approximately $11 million.

Our net cash provided by operating activities included a reduction of approximately $23 million, a reduction of approximately $51 million and a benefit of approximately $44 million for the years ended December 31, 2017, 2016 and 2015, respectively, associated with changes in working capital items. Changes in working capital items adjust for the timing of receipts and payments of actual cash.

Cash flow used in investing activities. During the years ended December 31, 2017, 2016 and 2015, we invested approximately $1,581 million, $1,046 million and $2,185 million, respectively, for additions to oil and natural gas properties. Additionally, we completed acquisitions of oil and natural gas properties of approximately $908 million, $1,351 million and $259 million during the years ended December 31, 2017, 2016 and 2015, respectively. The primary reason for the differences in costs incurred and cash flow expenditures in 2017 was our issuance of approximately 2.2 million shares of common stock related to our Northern Delaware Basin acquisition and timing of payments. In 2016, the primary reason for the differences in costs incurred and cash flow expenditures was (i) our issuance of approximately 2.2 million shares of common stock related to our March 2016 acquisition, (ii) our issuance of approximately 3.9 million shares of common stock related to our Reliance Acquisition and (iii) timing of payments, while the difference in 2015 was primarily due to timing of payments.

The 2017 expenditures were primarily funded in part from (i) cash flows from operations, (ii) proceeds from our February 2017 divestiture of ACC and (iii) our issuance of approximately 2.2 million shares of common stock related to our Northern Delaware Basin acquisition. The 2016 expenditures were funded in part from (i) proceeds from our February 2016 divestiture, (ii) our issuance of approximately 2.2 million shares of common stock related to our March 2016 acquisition, (iii) proceeds from our August 2016 equity offering and (iv) our issuance of approximately 3.9 million shares of common stock related to our Reliance Acquisition. The 2015 expenditures were funded in part from borrowings under our credit facility and our equity offerings in 2015.

Cash flows used in investing activities decreased during the year ended December 31, 2017 as compared to 2016, primarily due to (i) an increase in proceeds from the disposition of assets of approximately $471 million from 2016 to 2017, (ii) a decrease of approximately $443 million for acquisitions of oil and natural gas properties from 2016 to 2017 and (iii) contributions to our equity method investments of approximately $56 million during 2016, while no contributions were made in 2017, partially offset by an increase of approximately $535 million for additions to oil and natural gas properties from 2016 to 2017.

Cash flows used in investing activities decreased during the year ended December 31, 2016 as compared to 2015, primarily due to (i) proceeds from the disposition of assets of approximately $332 million during 2016, (ii) a decrease of approximately $47 million in amounts invested in oil and natural gas properties from 2015 to 2016, (iii) contributions to our equity method investments of approximately $56 million during 2016 compared to contributions of approximately $91 million during 2015 and (iv) approximately $61 million invested in other property and equipment during 2016 compared to approximately $67 million in 2015, partially offset by a 2016 cash outflow for funds held in escrow of $43 million related to our January 2017 asset acquisition.

Cash flow from financing activities. Below is a description of our financing activities. During 2017, 2016 and 2015 we completed the following significant capital markets activities:

- In September 2017, we issued $1,800 million in aggregate principal amount of the 2017 Notes, for which we received net proceeds of approximately $1,777 million. We used the net proceeds from the offering, together with cash on hand and borrowings under our credit facility, to fund the (i) Tender Offer of $1,232 million principal amount of the 5.5% Notes at a price equal to 102.934 percent of par and (ii) satisfaction and discharge of our remaining obligations of $918 million principal amount under the indentures of the 5.5% Notes at a price equal to 102.75 percent of par. The early extinguishment price included approximately $36 million associated with the premium paid for the Tender Offer, approximately $25 million for the make-whole premium paid for the early extinguishment of the 5.5% Notes and approximately $2 million for prepaid interest as part of the satisfaction and discharge.

- In December 2016, we issued $600 million in aggregate principal amount of 4.375% senior notes due 2025 at par, for which we received net proceeds of approximately $592 million. We used the net proceeds from the offering to fund the satisfaction and discharge of our obligations under the indenture of the $600 million outstanding principal amount of the 6.5% Notes at a price equal to 103.25 percent of par. The early extinguishment price included the make-whole premium of $20 million.

- In September 2016, we redeemed the $600 million outstanding principal amount of the 7.0% Notes at a price equal to 103.5 percent of par. The redemption price included the make-whole premium for the early redemption of $21 million.

- In August 2016, we issued approximately 10.4 million shares of our common stock in a public offering at $130.90 per share and received net proceeds of approximately $1.3 billion. We used a portion of the net proceeds to finance part of the cash portion of the purchase price for the Reliance Acquisition and to fund part of the early redemption of the 7.0% Notes and the remainder for general corporate purposes.

- In October 2015, we issued approximately 8.9 million shares of our common stock in a public offering at $92.50 per share and received net proceeds of approximately $794 million. We used a portion of the net proceeds from this offering to repay all outstanding borrowings under our credit facility and used the remainder for general corporate purposes and for funding of our 2016 acquisitions.

- In March 2015, we issued 6.9 million shares of our common stock in a public offering at $107.49 per share and received net proceeds of approximately $742 million. We used a portion of the net proceeds from this offering to repay all outstanding borrowings under our credit facility and the remainder for general corporate purposes.

- During 2017, we had net borrowings on our credit facility of $322 million.

- During 2016, we had no outstanding borrowings under our credit facility.

In April 2017, we amended our credit facility to decrease our unused lender commitments. In September 2017, we elected to enter into an Investment Grade Period under our credit facility, which had the effect of releasing all collateral formerly securing the credit facility. If the Investment Grade Period under the credit facility terminates (whether automatically or by our election), the credit facility will once again be secured by a first lien on substantially all of our oil and natural gas properties and by a pledge of the equity interests in our subsidiaries. At December 31, 2017, we had unused commitments on our credit facility of $1.7 billion.

Advances on our credit facility bear interest, at our option, based on: (i) an alternative base rate, which is equal to the highest of (a) the prime rate of JPMorgan Chase Bank (4.50 percent at December 31, 2017), (b) the federal funds effective rate plus 0.5 percent and (c) LIBOR plus 1.0 percent; or (ii) LIBOR. The credit facility's interest rates and commitment fees on the unused portion of the available commitment vary depending on our credit ratings from Moody's and S&P. At our current credit ratings, LIBOR Rate Loans and Alternate Base Rate Loans bear interest margins of 150 basis points and 50 basis points per annum, respectively, and commitment fees on the unused portion of the available commitment are 25 basis points per annum.

In conducting our business, we may utilize various financing sources, including the issuance of (i) fixed and floating rate debt, (ii) convertible securities, (iii) preferred stock, (iv) common stock and (v) other securities. Historically, we have demonstrated our use of the capital markets by issuing common stock and senior unsecured debt. There are no assurances that we can access the capital markets to obtain additional funding, if needed, and at cost and terms that are favorable to us. We may also sell assets and issue securities in exchange for oil and natural gas assets or interests in energy companies. Additional securities may be of a class senior to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined from time to time. Utilization of some of these financing sources may require approval from the lenders under our credit facility.

Liquidity. Our principal source of liquidity is available borrowing capacity under our credit facility. At December 31, 2017, our commitments from our bank group were $2.0 billion, of which $1.7 billion was unused commitments. Subsequent to December 31, 2017, our cash position increased by approximately $250 million as a result of completing two divestitures of oil and natural gas properties located in the Southern Delaware Basin core area.

During 2017, we decreased our annual interest expense and extended the average maturity on our senior notes from six to 16 years by issuing the 2017 Notes and completing the satisfaction and discharge of the 5.5% Notes. We also note that the TCJA may have longer-term impacts on our liquidity and financial position, primarily as a result of the federal statutory tax rate changing to 21 percent from 35 percent and repeal of the corporate alternative minimum tax. Beginning January 1, 2018, our income will be subject to the new 21 percent federal statutory tax rate, which will allow us to retain a greater percentage of earnings and improve our consolidated results of operations.

Debt ratings. We receive debt credit ratings from S&P, Moody’s and Fitch, which are subject to regular reviews. In August 2017, our long-term debt was assigned a first-time investment grade rating by Fitch, and our rating by S&P was raised to an investment grade rating. In determining our ratings, the agencies consider a number of qualitative and quantitative factors, including, but not limited to, the industry in which we operate, production growth opportunities, liquidity, debt levels and asset and reserve mix.

A downgrade in our credit ratings could (i) negatively impact our costs of capital and our ability to effectively execute aspects of our strategy, (ii) affect our ability to raise debt in the public debt markets, and the cost of any new debt could be much higher than our outstanding debt, and (iii) negatively affect our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing. Further, if we are unable to maintain credit ratings of “Ba2” or better from Moody’s and “BB” or better from S&P, the Investment Grade Period will automatically terminate and cause the credit facility to once again be secured by a first lien on substantially all of our oil and natural gas properties and by a pledge of the equity interests in our subsidiaries. These and other impacts of a downgrade in our credit ratings could have a material adverse effect on our business, financial condition and results of operations.

As of the filing of this Annual Report on Form 10-K, no changes in our credit ratings have occurred; however, we cannot be assured that our credit ratings will not be downgraded in the future.

Book capitalization and current ratio. Our net book capitalization at December 31, 2017 was $11.6 billion, consisting of debt of $2.7 billion and stockholders' equity of $8.9 billion. Our net book capitalization at December 31, 2016 was $10.2 billion, consisting of $0.1 billion of cash and cash equivalents, debt of $2.7 billion and stockholders' equity of $7.6 billion. Our ratio of net debt to net book capitalization was 23 percent and 26 percent at December 31, 2017 and 2016, respectively. Our ratio of current assets to current liabilities was 0.51 to 1.0 at December 31, 2017 as compared to 0.75 to 1.0 at December 31, 2016. The ratio of current assets to current liabilities at December 31, 2016 reflects the reclassification of certain prior period amounts to conform to the 2017 presentation. Both our ratio of net debt to net book capitalization and our ratio of current assets to current liabilities were impacted subsequent to December 31, 2017 by our two January 2018 divestitures.

Inflation and changes in prices. Our revenues, the value of our assets and our ability to obtain bank financing or additional capital on attractive terms have been and will continue to be affected by changes in commodity prices and the costs to produce our reserves. Commodity prices are subject to significant fluctuations that we are unable to control or predict. During the year ended December 31, 2017, we received an average of $48.13 per barrel of oil and $3.07 per Mcf of natural gas before consideration of commodity derivative contracts compared to $39.90 and $44.69 per barrel of oil and $2.23 and $2.46 per Mcf of natural gas in the years ended December 31, 2016 and 2015, respectively. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business.

Critical Accounting Policies and Practices

Our historical consolidated financial statements and related notes to consolidated financial statements contain information that is pertinent to our management's discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management's opinion, the more significant reporting areas impacted by management's judgments and estimates are the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations, impairment of long-lived assets, valuation of stock-based compensation, valuation of business combinations, accounting and valuation of nonmonetary transactions, valuation of financial derivative instruments and income taxes. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known.

Successful Efforts Method of Accounting

We utilize the successful efforts method of accounting for our oil and natural gas exploration and development activities. Under this method, exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment, undeveloped leases and developmental dry holes are capitalized. Exploratory drilling costs are initially capitalized, but are charged to expense if and when a well is determined not to have found proved reserves. Generally, a gain or loss is recognized when producing fields are sold. This accounting method may yield significantly different results than the full cost method of accounting.

The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that proved reserves have been discovered may take considerable time, and requires both judgment and application of industry experience. The evaluation of oil and natural gas leasehold acquisition costs included in unproved properties requires management's judgment to estimate the fair value of such properties. Drilling activities in an area by other companies may also effectively impair our leasehold positions.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties or projects are periodically assessed for impairment of value by considering future drilling plans, the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects.

Depletion of capitalized drilling and development costs of oil and natural gas properties is computed using the unit-of-production method on total estimated proved developed oil and natural gas reserves. Depletion of producing leaseholds is based on the unit-of-production method using our total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. Service properties, equipment and other assets are depreciated using the straight-line method over estimated useful lives of two to 39 years. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated depreciation and depletion are eliminated from the accounts and the resulting gain or loss is recognized.

Oil and Natural Gas Reserves and Standardized Measure of Discounted Net Future Cash Flows

This report presents estimates of our proved reserves as of December 31, 2017, which have been prepared and presented in accordance with SEC guidelines. The pricing that was used for estimates of our reserves as of December 31, 2017 was based on the 12-month unweighted average of the first-day-of-the-month WTI posted price of $47.79 per Bbl for oil and Henry Hub spot natural gas price of $2.98 per MMBtu for natural gas.

Our independent engineers and technical staff prepare the estimates of our oil and natural gas reserves and associated future net cash flows. Even though our independent engineers and technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Reserve estimates are updated at least annually and consider recent production levels and other technical information about each field. Periodic revisions to the estimated reserves and future net cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future depletion and result in impairment of long-lived assets that may be material.

It should not be assumed that the Standardized Measure included in this report as of December 31, 2017 is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the 2017 Standardized Measure on the 12-month unweighted average of the first-day-of-the-month pricing for oil and natural gas and prevailing costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs utilized in the estimate. See “Item 1A. Risk Factors” and “Item 2. Properties” for additional information regarding estimates of proved reserves.

Our estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which we record depletion expense will increase, reducing future earnings. Such a decline may result from lower commodity prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of our assessment of our proved properties for impairment.

Asset Retirement Obligations

There are legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and the normal operation of a long-lived asset. The primary impact of this relates to oil and natural gas wells on which we have a legal obligation to plug and abandon. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and, generally, a corresponding increase in the carrying amount of the related long-lived asset. The determination of the fair value of the liability requires us to make numerous judgments and estimates, including judgments and estimates related to future costs to plug and abandon wells, future inflation rates and estimated lives of the related assets. When the judgments used to estimate the initial fair value of the asset retirement obligation change, an adjustment is recorded to both the obligation and the carrying amount of the related long-lived asset. Historically, there have been no significant revisions to our initial estimates once future results became known. See Note 5 to the Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our asset retirement obligations.

Impairment of Long-Lived Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than management's estimates of its future net cash flows, including cash flows from proved reserves, risk-adjusted probable and possible reserves, and integrated assets. If the carrying value of the long-lived assets exceeds the sum of estimated undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the assets. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates, cash flows from integrated assets and other factors. The need to test an asset for impairment may result from significant declines in sales prices or downward revisions in estimated quantities of oil and natural gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded. At December 31, 2017, our estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2018 price of $59.55 per barrel of oil decreasing to a 2024 price of $51.82 per barrel of oil marginally recovering to a 2025 price of $51.83 per barrel of oil. Similarly, natural gas prices ranged from a 2018 price of $2.84 per Mcf of natural gas decreasing to a 2019 price of $2.81 per Mcf then rising to a 2025 price of $2.99 per Mcf of natural gas. Both oil and natural gas commodity prices for this purpose were held flat after 2025.

Unproved oil and natural gas properties are periodically assessed for impairment by considering future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales and expiration of all or a portion of the projects. During the years ended December 31, 2017, 2016 and 2015, we recognized expense of approximately

$29 million, $60 million and $35 million, respectively, related to abandoned and expiring acreage, which is included in exploration and abandonments expense in the accompanying consolidated statements of operations.

Valuation of Stock-Based Compensation

In accordance with GAAP, we calculate the fair value of stock-based compensation using various valuation methods. The valuation methods require the use of estimates to derive the inputs necessary to determine fair value. We utilize (i) the average of the high and low stock price on the date of grant for the fair value of restricted stock awards and (ii) the Monte Carlo simulation method for the fair value of performance unit awards. The significant assumptions used in these models include expected volatility, expected term, risk-free interest rate, forfeiture rate, and the probability of meeting performance targets. Each of these valuation methods were chosen as management believes they give the best estimate of fair value for the respective stock-based awards. See Note 6 to the Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information regarding our stock-based compensation.

Valuation of Business Combinations

In connection with a purchase business combination, the acquiring company must record assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant assumptions related to the estimated fair values assigned to proved and unproved oil and natural gas properties and integrated assets. To estimate the fair values of these properties, we utilize estimates of oil and natural gas reserves. We make future price assumptions to apply to the estimated reserves quantities acquired and estimate future operating and development costs to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate is subject to additional project-specific risking factors. To estimate the fair value of unproved properties, we apply risk-weighting factors of the future net cash flows of unproved reserves, or we may evaluate acreage values through recent market transactions in the area.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in a higher depletion expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded. Historically, we have had no material revisions to valuations of business combinations once actual results became known.

Accounting and Valuation of Nonmonetary Transactions

In connection with nonmonetary transactions, which include exchanges of producing and non-producing assets, we must evaluate the transaction to determine appropriate accounting treatment. In general, the basic principle of accounting for nonmonetary transactions is based on the fair values involved, which is the same basis used in monetary transactions and results in the recognition of gains and losses. However, certain nonmonetary transactions meet criteria that require modification of the basic principle that necessitate recording values based on historical book value. We determine the treatment of nonmonetary transactions based on the individual facts and circumstances of each transaction. In cases where nonmonetary transactions are recorded at fair value, we make various assumptions. The most significant assumptions are related to the estimated fair values assigned to proved and unproved oil and natural gas properties, similar to our valuation of the fair value of oil and natural gas assets acquired during a business combination described above. Any resulting difference between the fair value of the assets involved and their carrying value is recorded as a gain or loss in the consolidated statement of operations.

Estimated fair values assigned to assets exchanged can have a significant effect on our results of operations in the future. If future commodity prices or reserves quantities are lower than those originally used to determine fair value or if future operating expenses or development costs are higher than those originally used to determine fair value, we would record an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

Valuation of Financial Derivative Instruments

In order to reduce commodity price uncertainty and increase cash flow predictability relating to the marketing of our oil and natural gas, we enter into commodity price hedging arrangements with respect to a portion of our expected production. In addition, we have used derivative instruments in connection with acquisitions and certain price-sensitive projects. Management exercises significant judgment in determining the types of instruments to be used, production volumes to be hedged, prices at which to hedge and the counterparties' creditworthiness. All derivative instruments are reflected at fair value in our consolidated balance sheets.

Our open commodity derivative instruments were in a net liability position with a fair value of $379 million at December 31, 2017. In order to determine the fair value at the end of each reporting period, we compute discounted cash flows for the duration of each commodity derivative instrument using the terms of the related contract. Inputs consist of published forward commodity price curves as of the date of the estimate. We compare these prices to the price parameters contained in our hedge contracts to determine estimated future cash inflows or outflows. We then discount the cash inflows or outflows using a combination of published LIBOR rates and Eurodollar futures rates. The fair values of our commodity derivative assets and liabilities include a measure of credit risk based on average published yields by credit rating.

Changes in the fair values of our commodity derivative instruments have a significant impact on our net income because we follow mark-to-market accounting and recognize all gains and losses on such instruments in earnings in the period in which they occur. For the year ended December 31, 2017, we reported a $126 million loss on commodity derivative instruments.

We compare our estimates of the fair values of our commodity derivative instruments with those provided by our counterparties. There have been no significant differences.

Income Taxes

On December 22, 2017, the President signed the TCJA into law, which enacted significant changes to the federal income tax laws. According to ASC 740, “Income Taxes,” a company is required to record the effects of an enacted tax law or rate change in the period of enactment. Based on the comprehensiveness of TCJA and the challenges faced by calendar year-end registrants to complete the accounting for the income tax effects of the TCJA in the period of enactment, the SEC issued SAB 118 “Income Tax Accounting Implications of the Tax Cuts and Jobs Act,” which allows companies to report provisional amounts when based on reasonable estimates and to adjust these amounts during a measurement period of up to one year.

Although we have performed an initial assessment of the TCJA, we recognize it is a comprehensive tax bill and the ultimate impacts may differ from our initial estimates due to changes in our interpretations as a result of additional regulatory guidance that may become available. As such, we have elected to apply SAB 118 and have recorded provisional amounts of our income tax balances in our consolidated financial statements. We will continue to monitor new tax law interpretations, which could potentially affect the measurement of these balances or potentially give rise to revised deferred tax amounts. We have calculated our best estimate of the impact of the TCJA, including the federal statutory tax rate change noted below, in our year-end income tax provision in accordance with our understanding of the TCJA and guidance available as of the date of this filing and as a result have recorded $398 million as a decrease to our income tax provision at December 31, 2017. The provisional amount related to the re-measurement of certain deferred tax assets and liabilities based on the rates at which they are expected to reverse in the future was $398 million.

Our provision for income taxes includes both federal and state taxes of the jurisdictions in which we operate. We estimate our overall tax rate using a combination of the enacted federal statutory tax rate, which decreased from 35 percent to 21 percent effective January 1, 2018 as a result of the TCJA, and a blend of enacted state tax rates. Acquisitions or dispositions of assets and changes in our drilling plan by tax jurisdiction could change the apportionment of our state taxes, which would impact our overall tax rate.

The TCJA also repealed the corporate AMT for tax years beginning after December 31, 2017, and provides that existing AMT credit carryovers are refundable beginning with the 2018 tax year. We have approximately $10 million of AMT credit carryovers that are expected to be fully refunded by 2022.

Our federal and state income tax returns are not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities, which are based on numerous judgments and assumptions inherent in the determination of future taxable income, at the end of each period as well as the effects of tax rate changes and tax credits. Adjustments related to these estimates are recorded in our tax provision in the period in which we finalize our income tax returns. Historically, we have had no significant changes as a result of filing our tax returns. Material changes to our tax accruals may occur in the future based on audits, changes in legislation or resolution of pending matters.

See Note 11 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplemental Data” for additional information regarding our current year income tax expense and deferred tax balances.

New accounting pronouncements issued but not yet adopted

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," which outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services.

In August 2015, the FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date," which deferred the effective date of ASU No. 2014-09 by one year. The new standard is now effective for annual reporting periods beginning after December 15, 2017. We will use the modified retrospective method to adopt the standard, meaning the cumulative effect of initially applying the standard will be recognized with an adjustment to retained earnings on January 1, 2018. We have completed our internal evaluation of the adoption of this standard, which included a review of revenue-related contracts with customers and the application of the new revenue recognition model against those contracts and have updated our revenue recognition policy and our related internal control documentation, processes and controls to conform to the new standard. We will also expand our revenue recognition related disclosures. Including those changes previously discussed, this new guidance will not have a material impact on our consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, "Leases (Topic 842)," which supersedes current lease guidance. The new lease standard requires all leases with a term greater than one year to be recognized on the balance sheet while maintaining substantially similar classifications for financing and operating leases. Lease expense recognition on the consolidated statements of operations will be effectively unchanged. This guidance is effective for reporting periods beginning after December 15, 2018, and early adoption is permitted. We do not plan to early adopt the standard. We enter into lease agreements to support our operations. These agreements are for leases on assets such as office space, vehicles, field services, well equipment and drilling rigs. We are substantially complete with the process of reviewing and determining the contracts to which this new guidance applies. We are currently enhancing our accounting systems in order to track and calculate additional information necessary for adoption of this standard. We believe this new guidance will have a moderate impact to our consolidated balance sheets due to the recognition of right-of-use assets and lease liabilities that are not currently recognized under currently applicable guidance.

In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments," which replaces the current "incurred loss" methodology for recognizing credit losses with an "expected loss" methodology. This new methodology requires that a financial asset measured at amortized cost be presented at the net amount expected to be collected. This standard is intended to provide more timely decision-useful information about the expected credit losses on financial instruments. This guidance is effective for fiscal years beginning after December 15, 2019, and early adoption is allowed as early as fiscal years beginning after December 15, 2018. We do not believe this new guidance will have a material impact on our consolidated financial statements.

In January 2017, the FASB issued ASU No. 2017-01, “Business Combinations (Topic 805): Clarifying the Definition of a Business,” with the objective of adding guidance to assist in evaluating whether transactions should be accounted for as asset acquisitions or as business combinations. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the acquired assets is concentrated in a single asset or a group of similar assets, the set is not a business. If the screen is not met, to be considered a business, the set must include an input and a substantive process that together significantly contribute to the ability to create output. This new guidance is effective for annual periods beginning after December 15, 2017, and early adoption is allowed. We do not believe this new guidance will have a material impact on our consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to a variety of market risks, including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments. The following quantitative and qualitative information is provided about financial instruments to which we are a party at December 31, 2017, and from which we may incur future gains or losses from changes in market interest rates or commodity prices and losses from extension of credit. We do not enter into derivative or other financial instruments for speculative or trading purposes.

Hypothetical changes in interest rates and commodity prices chosen for the following estimated sensitivity analysis are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. However, since it is not possible to accurately predict future changes in interest rates and commodity prices, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Credit risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies and refineries and, to a lesser extent, our derivative counterparties. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty's creditworthiness.

We have entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of set-off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note 8 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our derivative activities.

Commodity price risk. We are exposed to market risk as the prices of our commodities are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of our commodities, we have entered into, and may in the future enter into, additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management arrangements are recorded at fair value and thus changes to the future commodity prices will have an impact on net income. The following table sets forth the hypothetical impact on the fair value of the commodity price risk management arrangements from an average increase and decrease in the commodity price of $5.00 per Bbl of oil and $0.50 per MMBtu of natural gas from the commodity prices at December 31, 2017:

	2017		2016	
(in millions)	**Increase of $5.00 per Bbl and $0.50 per MMBtu**	**Decrease of $5.00 per Bbl and $0.50 per MMBtu**	**Increase of $5.00 per Bbl and $0.50 per MMBtu**	**Decrease of $5.00 per Bbl and $0.50 per MMBtu**
Gain (loss):				
Oil derivatives	$ (290)	$ 290	$ (216)	$ 216
Natural gas derivatives	(37)	37	(33)	33
Total	$ (327)	$ 327	$ (249)	$ 249

Our commodity price risk management arrangements expose us to risk of non-performance by the counterparty to the agreements. Our exposure to the risk of non-performance is diversified over large, investment grade financial institutions. In addition, we have master netting agreements with the counterparties that allow for offsetting payables against receivables from separate contracts with the same counterparty. At December 31, 2017, the counterparties to our commodity price risk management arrangements include thirteen financial institutions, all of which are lenders to our credit facility. Risk of non-performance is considered when determining the fair value of our commodity price risk management arrangements. The fair value adjustment for non-performance risk was immaterial at December 31, 2017. If at any point a counterparty's financial position deteriorates, such deterioration could have a significant impact on the collectability of that counterparty's related commodity price risk management arrangement asset.

At December 31, 2017, we had (i) oil price swaps that settle on a monthly basis covering future oil production from January 1, 2018 through December 31, 2019 and (ii) oil basis swaps covering our Midland to Cushing basis differential from January 1, 2018 to December 31, 2019. See Note 8 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information on the commodity derivative instruments. The average NYMEX oil price for the year ended December 31, 2017, was $50.97 per Bbl. At February 16, 2018, the NYMEX oil price was $61.68 per Bbl.

At December 31, 2017, we had natural gas price swaps that settle on a monthly basis covering future natural gas production from January 1, 2018 to December 31, 2019. See Note 8 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information on our commodity derivative instruments. The average NYMEX natural gas price for the year ended December 31, 2017 was $3.02 per MMBtu. At February 16, 2018, the NYMEX natural gas price was $2.56 per MMBtu.

A decrease in the average forward NYMEX oil and natural gas prices below those at December 31, 2017 would decrease the fair value liability of our commodity derivative contracts from their recorded balances at December 31, 2017. Changes in the recorded fair value of our commodity derivative contracts are marked to market through earnings as gains or losses. The potential decrease in our fair value liability would be recorded in earnings as a gain. However, an increase in the average forward NYMEX oil and natural gas prices above those at December 31, 2017 would increase the fair value liability of our commodity derivative contracts from their recorded balances at December 31, 2017. The potential increase in our fair value liability would be recorded in earnings as a loss. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our commodity derivative contracts.

We recorded a loss on derivatives of $126 million for the year ended December 31, 2017, compared to a loss of $369 million for the year ended December 31, 2016. The largest factor in the change from 2016 to 2017 related to the change in commodity future price curves at the respective measurement and settlement periods.

The fair value of our derivative instruments is determined based on our valuation models. We did not change our valuation method during the year ended December 31, 2017. See Note 8 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our derivative instruments. The following table reconciles the changes that occurred in the fair values of our derivative instruments during the year ended December 31, 2017:

(in millions)		**Commodity Derivative Instruments Net Liabilities (a)**
Fair value of contracts outstanding at December 31, 2016	$	(174)
Changes in fair values (b)		(126)
Contract maturities		(79)
Fair value of contracts outstanding at December 31, 2017	$	(379)

(a) Represents the fair values of open derivative contracts subject to market risk.

(b) At inception, new derivative contracts entered into by us have no intrinsic value.

Interest rate risk. Our exposure to changes in interest rates relates primarily to debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. To reduce our exposure to changes in interest rates we may, in the future, enter into interest rate risk management arrangements for a portion of our outstanding debt. The agreements that we have entered into generally have the effect of providing us with a fixed interest rate for a portion of our variable-rate debt. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our credit facility, and the terms of our credit facility require us to pay higher interest rate margins as our credit ratings decrease.

We had total indebtedness of $322 million outstanding under our credit facility at December 31, 2017. The impact of a one percent increase in interest rates on this amount of debt would result in increased annual interest expense of approximately $3 million.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements and supplementary data are included in this report beginning on page F-1.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

We had no changes in, and no disagreements with, our accountants on accounting and financial disclosure.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective at December 31, 2017 at the reasonable assurance level.

Management's Report on Internal Control over Financial Reporting. The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements in a timely manner. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

As of December 31, 2017, management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria established in "Internal Control - Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that the Company maintained effective internal control over financial reporting at December 31, 2017.

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this annual report on Form 10-K, has issued its report on the effectiveness of the Company's internal control over financial reporting at December 31, 2017. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting at December 31, 2017, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

Changes in Internal Control over Financial Reporting. There have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Concho Resources Inc.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Concho Resources Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2017, and our report dated February 21, 2018 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and limitations of internal control over financial reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

February 21, 2018

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Item 10 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2017.

Code of Ethics. Our board of directors has adopted a financial code of ethics applicable to our Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer and other senior financial officers, and a code of business conduct and ethics applicable to our directors, officers and employees, in accordance with applicable U.S. federal securities laws and the corporate governance rules of the NYSE (the “Codes”). The Codes can be found on our website located at *www.concho.com*. We intend to disclose future amendments to certain provisions of the Codes, and waivers of the Codes granted to executive officers and directors, on our website within four business days following the date of the amendment or waiver.

Item 11. Executive Compensation

Item 11 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2017.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Equity compensation plans. At December 31, 2017, a total of 10,500,000 shares of common stock were authorized for issuance under our equity compensation plan. In the table below, we describe certain information about these shares and the equity compensation plan which provides for their authorization and issuance. Included in column (1) are (i) unvested performance units at the maximum potential payout percentage and (ii) performance units relating to the performance period that ended on December 31, 2017 at the actual payout percentage of 300 percent. You can find descriptions of our stock incentive plan under

Note 6 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.”

Plan category	(1) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(2) Weighted average exercise price of outstanding options	(3) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (1))
Equity compensation plan approved by the security holders (a)	1,189,773	$ - (c)	2,126,731
Equity compensation plan not approved by the security holders (b)	-	$ -	-
Total	1,189,773		2,126,731

(a) 2015 Stock Incentive Plan. See Note 6 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.”
(b) None.
(c) Performance unit awards do not have an exercise price and, therefore, have been excluded from the weighted average exercise price calculation in column (2).

The remaining information required by Item 12 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2017.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Item 13 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2017.

Item 14. Principal Accounting Fees and Services

Item 14 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2017.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) Listing of Financial Statements

Financial Statements

The following consolidated financial statements are included in “Item 8.Financial Statements and Supplementary Data”:

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets at December 31, 2017 and 2016

Consolidated Statements of Operations for the Years Ended December 31, 2017, 2016 and 2015

Consolidated Statements of Stockholders’ Equity for the Years Ended December 31, 2017, 2016 and 2015

Consolidated Statements of Cash Flows for the Years Ended December 31, 2017, 2016 and 2015

Notes to Consolidated Financial Statements

Unaudited Supplementary Data

(b) Exhibits

The exhibits to this report required to be filed pursuant to Item 15(b) are listed below and in the “Index to Exhibits” attached hereto.

(c) Financial Statement Schedules

No financial statement schedules are required to be filed as part of this report or they are inapplicable.

Exhibits

Exhibit Number	Description
3.1	Restated Certificate of Incorporation of Concho Resources Inc. (filed as Exhibit 3.1 to the Company’s Current Report on Form 8-K on August 8, 2007, and incorporated herein by reference).
3.2	Fourth Amended and Restated Bylaws of Concho Resources Inc., as amended January 2, 2018 (filed as Exhibit 3.1 to the Company’s Current Report on Form 8-K on January 4, 2018, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company’s Annual Report on Form 10-K on February 22, 2013, and incorporated herein by reference).
4.2	Senior Indenture, dated September 18, 2009, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company’s Current Report on Form 8-K on September 22, 2009, and incorporated herein by reference).
4.3	Second Supplemental Indenture, dated November 3, 2010, between Concho Oil & Gas LLC, COG Holdings LLC, COG Exchange Properties LLC, Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.4 to the Post-Effective Amendment to the Company’s Registration Statement on Form S-3 on December 7, 2010, and incorporated herein by reference).

4.4 Fifth Supplemental Indenture, dated December 12, 2011, between COG Production LLC, COG Acreage LP, Delaware River SWD, LLC, Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.7 to the Company's Annual Report on Form 10-K on February 24, 2012, and incorporated herein by reference).

4.5 Sixth Supplemental Indenture, dated March 12, 2012, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on March 12, 2012, and incorporated herein by reference).

4.6 Seventh Supplemental Indenture, dated August 17, 2012, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on August 17, 2012, and incorporated herein by reference).

4.7 Tenth Supplemental Indenture, dated December 28, 2016, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on December 28, 2016, and incorporated herein by reference).

4.8 Twelfth Supplemental Indenture, dated September 26, 2017, among Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on September 26, 2017, and incorporated herein by reference).

4.9 Thirteenth Supplemental Indenture, dated September 26, 2017, among Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on September 26, 2017, and incorporated herein by reference).

4.10 Form of 4.375% Senior Notes due 2025 (Annex A, Exhibit 4.1 to the Company's Current Report on Form 8-K filed on December 28, 2016, and incorporated herein by reference).

4.11 Form of 3.75% Senior Notes due 2027 (Annex A, Exhibit 4.1 to the Company's Current Report on Form 8-K filed on September 26, 2017, and incorporated herein by reference).

4.12 Form of 4.875% Senior Notes due 2047 (Annex A, Exhibit 4.2 to the Company's Current Report on Form 8-K filed on September 26, 2017, and incorporated herein by reference).

10.1 ** Form of Performance Unit Award Agreement (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 4, 2013, and incorporated herein by reference).

10.2 ** Concho Resources Inc. 2015 Stock Incentive Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on June 5, 2015, and incorporated herein by reference).

10.3 ** Form of Nonstatutory Stock Option Agreement (filed as Exhibit 10.16 to the Company's Annual Report on Form 10-K on March 28, 2008, and incorporated herein by reference).

10.4 ** Form of Restricted Stock Agreement (for officers) (filed as Exhibit 10.1 to the Company's Annual Report on Form 10-K on February 22, 2013, and incorporated herein by reference).

10.5 ** Form of Restricted Stock Agreement (for non-employee directors) (filed as Exhibit 10.18 to the Company's Annual Report on Form 10-K on March 28, 2008, and incorporated herein by reference).

10.6 ** Employment Agreement, dated December 19, 2008, between Concho Resources Inc. and Timothy A. Leach (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).

10.7 ** Employment Agreement, dated December 19, 2008, between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).

10.8 ** Employment Agreement, dated November 5, 2009, between Concho Resources Inc. and C. William Giraud IV (filed as Exhibit 10.18 to the Company's Annual Report on Form 10-K on February 26, 2010, and incorporated herein by reference).

10.9 ** Employment Agreement, dated March 19, 2014, between Concho Resources Inc. and Jack F. Harper (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on March 24, 2014, and incorporated herein by reference).

10.10 ** Form of First Amendment to Employment Agreement between Concho Resources Inc. and each of Messrs. Leach, Giraud and Wright (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on May 6, 2011, and incorporated herein by reference).

10.11 ** Form of Indemnification Agreement between Concho Resources Inc. and each of the officers and directors thereof (filed as Exhibit 10.24 to the Company's Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).

10.12 ** Indemnification Agreement, dated February 27, 2008, by and between Concho Resources Inc. and William H. Easter III (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 4, 2008, and incorporated herein by reference).

10.13 ** Indemnification Agreement, dated November 5, 2009, by and between Concho Resources Inc. and Mark B. Puckett (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on November 12, 2009, and incorporated herein by reference).

10.14 ** Indemnification Agreement, dated November 5, 2009, by and between Concho Resources Inc. and C. William Giraud (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on November 12, 2009, and incorporated herein by reference).

10.15 ** Form of Director and Officer Indemnification Agreement between Concho Resources Inc. and each of Messrs. Surma and Harper (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 24, 2014, and incorporated herein by reference).

10.16 ** Indemnification Agreement, dated January 10, 2012, between Concho Resources Inc. and Gary A. Merriman (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 12, 2012, and incorporated herein by reference).

10.17 ** Form of Indemnification Agreement, dated March 27, 2017, between Concho Resources Inc. and Susan J. Helms (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 28, 2017, and incorporated herein by reference).

10.18 ** Retirement Agreement, dated May 17, 2017, by and between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on May 19, 2017, and incorporated herein by reference).

10.19 ** Performance Unit Award Agreement, dated January 2, 2018, by and between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 4, 2018, and incorporated herein by reference).

10.20 ** Restricted Stock Agreement, dated January 2, 2018, between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on January 4, 2018, and incorporated herein by reference).

10.21 Second Amended and Restated Credit Agreement, dated as of May 9, 2014, among Concho Resources Inc., the lenders party thereto, JPMorgan Chase Bank, N.A., as administrative agent, and the co-syndication agents and co-documentation agents named therein (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on May 12, 2014, and incorporated herein by reference).

10.22 First Amendment to Second Amended and Restated Credit Agreement, dated as of April 8, 2015, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 9, 2015, and incorporated herein by reference).

10.23 Second Amendment to Second Amended and Restated Credit Agreement, dated as of April 12, 2017, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on August 3, 2017, and incorporated herein by reference).

10.24 Purchase and Sale Agreement, dated August 15, 2016, by and among COG Operating LLC, as purchaser, Concho Resources Inc., as purchaser parent, and Reliance Energy, Inc., Reliance Exploration, Ltd., Reliance Energy-WA, LLC, Reliance Energy-GF, LLC and the other persons named as sellers therein, as the seller parties (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on August 16, 2016, and incorporated herein by reference).

10.25 Securities Purchase Agreement, dated January 19, 2017, between COG Operating LLC, as seller, and Plains Pipeline, L.P., as purchaser (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on May 4, 2017, and incorporated herein by reference).

12.1 (a) Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Stock Dividends.

21.1 (a) Subsidiaries of Concho Resources Inc.

23.1 (a) Consent of Grant Thornton LLP.

23.2 (a) Consent of Netherland, Sewell & Associates, Inc.

23.3 (a) Consent of Cawley, Gillespie & Associates, Inc.

31.1 (a) Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.

31.2 (a) Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.

32.1 (b) Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350.

32.2 (b) Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350.

99.1 (a) Netherland, Sewell & Associates, Inc. Reserve Report.

99.2 (a) Cawley, Gillespie & Associates, Inc. Reserve Report.

101.INS (a) XBRL Instance Document.

101.SCH (a) XBRL Schema Document.

101.CAL (a) XBRL Calculation Linkbase Document.

101.DEF (a) XBRL Definition Linkbase Document.

101.LAB (a) XBRL Labels Linkbase Document.

101.PRE (a) XBRL Presentation Linkbase Document.

(a) Filed herewith.

(b) Furnished herewith.

** Management contract or compensatory plan or agreement

Item 16. Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONCHO RESOURCES INC.

Date:	February 21, 2018	By	/s/ Timothy A. Leach
			Timothy A. Leach Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ TIMOTHY A. LEACH Timothy A. Leach	Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)	February 21, 2018
/s/ JACK F. HARPER Jack F. Harper	President and Chief Financial Officer (Principal Financial Officer)	February 21, 2018
/s/ BRENDA R. SCHROER Brenda R. Schroer	Senior Vice President, Chief Accounting Officer and Treasurer (Principal Accounting Officer)	February 21, 2018
/s/ STEVEN L. BEAL Steven L. Beal	Director	February 21, 2018
/s/ TUCKER S. BRIDWELL Tucker S. Bridwell	Director	February 21, 2018
/s/ WILLIAM H. EASTER III William H. Easter III	Director	February 21, 2018
/s/ SUSAN J. HELMS Susan J. Helms	Director	February 21, 2018
/s/ GARY A. MERRIMAN Gary A. Merriman	Director	February 21, 2018
/s/ RAY M. POAGE Ray M. Poage	Director	February 21, 2018
/s/ MARK B. PUCKETT Mark B. Puckett	Director	February 21, 2018
/s/ JOHN P. SURMA John P. Surma	Director	February 21, 2018
/s/ E. JOSEPH WRIGHT E. Joseph Wright	Director, Executive Vice President and Chief Operating Officer	February 21, 2018

GLOSSARY OF TERMS

The following terms are used throughout this report:

Bbl One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to oil, condensate or natural gas liquids.

Bcf One billion cubic feet of natural gas.

Boe One barrel of oil equivalent, a standard convention used to express oil and natural gas volumes on a comparable oil equivalent basis. Natural gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of oil or condensate.

Basin A large natural depression on the earth's surface in which sediments accumulate.

Development wells Wells drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses, taxes and the royalty burden.

Exploratory wells Wells drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir.

Field An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

GAAP Generally accepted accounting principles in the United States of America.

Gross wells The number of wells in which a working interest is owned.

Horizontal drilling A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a high angle to vertical (which can be greater than 90 degrees) in order to stay within a specified interval.

Infill drilling Drilling into the same pool as known producing wells so that oil or natural gas does not have to travel as far through the formation.

LIBOR London Interbank Offered Rate, which is a market rate of interest.

MBbl One thousand barrels of oil, condensate or natural gas liquids.

MBoe One thousand Boe.

Mcf One thousand cubic feet of natural gas.

MMBoe One million Boe.

MMBtu One million British thermal units.

MMcf One million cubic feet of natural gas.

NYMEX The New York Mercantile Exchange.

NYSE The New York Stock Exchange.

Net acres The percentage of total acres an owner owns out of a particular number of acres within a specified tract. For example, an owner who has a 50 percent interest in 100 acres owns 50 net acres.

Net wells The total of fractional working interests owned in gross wells.

PV-10 When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses except for specific general and administrative expenses incurred to operate the properties, discounted to a present value using an annual discount rate of 10 percent. PV-10 is a non-GAAP financial measure.

Productive wells Wells that produce commercial quantities of hydrocarbons, exclusive of their capacity to produce at a reasonable rate of return.

Proved developed reserves Proved developed reserves are proved reserves that can be expected to be recovered:

(i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) through installed extraction equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Proved Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Proved Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Proved reserves Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) the area identified by drilling and limited by fluid contacts, if any, and

(B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (“LKH”) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (“HKO”) elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) the project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves Proved undeveloped oil and natural gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years from initial booking, unless the specific circumstances justify a longer time.

Recompletion The addition of production from another interval or formation in an existing wellbore.

Reservoir A formation beneath the surface of the earth from which hydrocarbons may be present. Its make-up is sufficiently homogenous to differentiate it from other formations.

Spacing The distance between wells producing from the same reservoir. Spacing is expressed in terms of acres, e.g., 40-acre spacing, and is established by regulatory agencies.

Standardized Measure The present value (discounted at an annual rate of 10 percent) of estimated future net revenues to be generated from the production of proved reserves net of estimated income taxes associated with such net revenues, as determined in accordance with FASB guidelines, without giving effect to non-property related expenses such as indirect general and administrative expenses, and debt service or to depreciation, depletion and amortization. Standardized measure does not give effect to derivative transactions.

Undeveloped acreage Acreage owned or leased on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Wellbore The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called a well or borehole.

Working interest The right granted to the lessee of a property to explore for and to produce and own oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Workover Operations on a producing well to restore or increase production.

WTI West Texas Intermediate - light, sweet blend of oil produced from fields in western Texas.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Financial Statements of Concho Resources Inc.:

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Concho Resources Inc.

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Concho Resources Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 21, 2018 expressed an unqualified opinion.

Basis for opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Company’s auditor since 2004.

Oklahoma City, Oklahoma

February 21, 2018

Concho Resources Inc.

Consolidated Balance Sheets

(in millions, except share and per share amounts)	**December 31, 2017**	**2016**
Assets		
Current assets:		
Cash and cash equivalents	$ -	$ 53
Accounts receivable, net of allowance for doubtful accounts:		
Oil and natural gas	331	220
Joint operations and other	212	238
Inventory	14	16
Derivative instruments	-	4
Prepaid costs and other	35	31
Total current assets	592	562
Property and equipment:		
Oil and natural gas properties, successful efforts method	21,267	18,476
Accumulated depletion and depreciation	(8,460)	(7,390)
Total oil and natural gas properties, net	12,807	11,086
Other property and equipment, net	234	216
Total property and equipment, net	13,041	11,302
Funds held in escrow	-	43
Deferred loan costs, net	13	11
Intangible assets, net	26	24
Other assets	60	177
Total assets	$ 13,732	$ 12,119
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable - trade	$ 43	$ 28
Bank overdrafts	116	-
Revenue payable	183	132
Accrued drilling costs	330	359
Derivative instruments	277	82
Other current liabilities	216	152
Total current liabilities	1,165	753
Long-term debt	2,691	2,741
Deferred income taxes	687	766
Noncurrent derivative instruments	102	96
Asset retirement obligations and other long-term liabilities	172	140
Commitments and contingencies (Note 10)		
Stockholders' equity:		
Common stock, $0.001 par value; 300,000,000 authorized; 149,324,849 and 146,488,685	-	-

shares issued at December 31, 2017 and 2016, respectively				
Additional paid-in capital		7,142		6,783
Retained earnings		1,840		884
Treasury stock, at cost; 598,049 and 429,708 shares at December 31, 2017 and 2016, respectively		(67)		(44)
Total stockholders’ equity		8,915		7,623
Total liabilities and stockholders’ equity	$	13,732	$	12,119

The accompanying notes are an integral part of these consolidated financial statements.

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Concho Resources Inc.

Consolidated Statements of Operations

(in millions, except per share amounts)	**Years Ended December 31, 2017**	**2016**	**2015**
Operating revenues:			
Oil sales	$ 2,092	$ 1,350	$ 1,540
Natural gas sales	494	285	264
Total operating revenues	2,586	1,635	1,804
Operating costs and expenses:			
Oil and natural gas production	408	320	390
Production and ad valorem taxes	199	131	151
Exploration and abandonments	59	77	59
Depreciation, depletion and amortization	1,146	1,167	1,223
Accretion of discount on asset retirement obligations	8	7	8
Impairments of long-lived assets	-	1,525	61
General and administrative (including non-cash stock-based compensation of $60, $59 and $63 for the years ended December 31, 2017, 2016 and 2015, respectively)	244	226	231
(Gain) loss on derivatives	126	369	(700)
(Gain) loss on disposition of assets, net	(678)	(118)	54
Total operating costs and expenses	1,512	3,704	1,477
Income (loss) from operations	1,074	(2,069)	327
Other income (expense):			
Interest expense	(146)	(204)	(215)
Loss on extinguishment of debt	(66)	(56)	-
Other, net	19	(9)	(15)
Total other expense	(193)	(269)	(230)
Income (loss) before income taxes	881	(2,338)	97
Income tax (expense) benefit	75	876	(31)
Net income (loss)	$ 956	$ (1,462)	$ 66
Earnings per share:			
Basic net income (loss)	$ 6.44	$ (10.85)	$ 0.54
Diluted net income (loss)	$ 6.41	$ (10.85)	$ 0.54

The accompanying notes are an integral part of these consolidated financial statements.

Concho Resources Inc.

Consolidated Statements of Stockholders' Equity

(in millions, except share data)	Common Stock Issued Shares (in thousands)	Common Stock Issued Amount	Additional Paid-in Capital	Retained Earnings	Treasury Stock Shares (in thousands)	Treasury Stock Amount	Total Stockholders' Equity
BALANCE AT JANUARY 1, 2015	113,265	$ -	$ 3,028	$ 2,280	260	$ (27)	$ 5,281
Net income	-	-	-	66	-	-	66
Issuance of common stock	15,755	-	1,536	-	-	-	1,536
Stock options exercised	5	-	-	-	-	-	-
Grants of restricted stock	452	-	-	-	-	-	-
Cancellation of restricted stock	(33)	-	-	-	-	-	-
Stock-based compensation	-	-	63	-	-	-	63
Excess tax benefits related to stock-based compensation	-	-	2	-	-	-	2
Purchase of treasury stock	-	-	-	-	46	(5)	(5)
BALANCE AT DECEMBER 31, 2015	129,444	-	4,629	2,346	306	(32)	6,943
Net loss	-	-	-	(1,462)	-	-	(1,462)
Issuance of common stock	10,350	-	1,327	-	-	-	1,327
Common stock issued in business combinations	6,134	-	768	-	-	-	768
Stock options exercised	23	-	1	-	-	-	1
Grants of restricted stock	451	-	-	-	-	-	-
Performance unit share conversion	180	-	-	-	-	-	-
Cancellation of restricted stock	(93)	-	-	-	-	-	-
Stock-based compensation	-	-	59	-	-	-	59
Tax deficiency related to stock-based compensation	-	-	(1)	-	-	-	(1)
Purchase of treasury stock	-	-	-	-	124	(12)	(12)
BALANCE AT DECEMBER 31, 2016	146,489	-	6,783	884	430	(44)	7,623
Adoption of ASU No. 2016-09 (Note 2)	-	-	8	-	-	-	8
BALANCE AT JANUARY 1, 2017	146,489	-	6,791	884	430	(44)	7,631
Net income	-	-	-	956	-	-	956
Common stock issued in business combinations	2,177	-	291	-	-	-	291

Stock options exercised	20	-	-	-	-	-	-
Grants of restricted stock	490	-	-	-	-	-	-
Performance unit share conversion	249	-	-	-	-	-	-
Cancellation of restricted stock	(100)	-	-	-	-	-	-
Stock-based compensation	-	-	60	-	-	-	60
Purchase of treasury stock	-	-	-	-	168	(23)	(23)
BALANCE AT DECEMBER 31, 2017	149,325	$ -	$ 7,142	$ 1,840	598	$ (67)	$ 8,915

The accompanying notes are an integral part of these consolidated financial statements.

Concho Resources Inc.

Consolidated Statements of Cash Flows

(in millions)	Years Ended December 31, 2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 956	$ (1,462)	$ 66
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,146	1,167	1,223
Accretion of discount on asset retirement obligations	8	7	8
Impairments of long-lived assets	-	1,525	61
Exploration and abandonments, including dry holes	27	57	34
Non-cash stock-based compensation expense	60	59	63
Deferred income taxes	(71)	(864)	30
(Gain) loss on disposition of assets, net	(678)	(118)	54
(Gain) loss on derivatives	126	369	(700)
Net settlements received from derivatives	79	625	633
Loss on extinguishment of debt	66	56	-
Other non-cash items	(1)	14	14
Changes in operating assets and liabilities, net of acquisitions and dispositions:			
Accounts receivable	(126)	32	128
Prepaid costs and other	(9)	6	(4)
Inventory	-	2	(5)
Accounts payable	14	15	(18)
Revenue payable	52	(38)	(68)
Other current liabilities	46	(68)	11
Net cash provided by operating activities	1,695	1,384	1,530
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to oil and natural gas properties	(1,581)	(1,046)	(2,185)
Acquisitions of oil and natural gas properties	(908)	(1,351)	(259)
Additions to property, equipment and other assets	(44)	(61)	(67)
Proceeds from the disposition of assets	803	332	-
Deposits on dispositions of oil and natural gas properties	29	-	-
Direct transaction costs for disposition of assets	(18)	-	-
Funds held in escrow	-	(43)	-
Contributions to equity method investments	-	(56)	(91)
Net cash used in investing activities	(1,719)	(2,225)	(2,602)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of debt	2,795	600	1,491
Payments of debt	(2,829)	(1,200)	(1,630)
Debt extinguishment costs	(63)	(42)	-
Excess tax benefit (deficiency) from stock-based compensation (Note 2)	-	(1)	2
Net proceeds from issuance of common stock	-	1,327	1,536

Payments for loan costs		(25)		(7)		-
Purchase of treasury stock		(23)		(12)		(5)
Increase (decrease) in bank overdrafts		116		-		(93)
Net cash provided by (used in) financing activities		(29)		665		1,301
Net increase (decrease) in cash and cash equivalents		(53)		(176)		229
Cash and cash equivalents at beginning of period		53		229		-
Cash and cash equivalents at end of period	$	-	$	53	$	229
SUPPLEMENTAL CASH FLOWS:						
Cash paid for interest	$	139	$	232	$	211
Cash paid for income taxes	$	13	$	-	$	4
NON-CASH INVESTING AND FINANCING ACTIVITIES:						
Issuance of common stock for business combinations	$	291	$	768	$	-

The accompanying notes are an integral part of these consolidated financial statements.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2017, 2016 and 2015

Note 1. *Organization and nature of operations*

Concho Resources Inc. (the “Company”) is a Delaware corporation formed on February 22, 2006. The Company’s principal business is the acquisition, development, exploration and production of oil and natural gas properties primarily located in the Permian Basin of southeast New Mexico and west Texas.

Note 2. *Summary of significant accounting policies*

Principles of consolidation. The consolidated financial statements of the Company include the accounts of the Company and its 100 percent owned subsidiaries. The consolidated financial statements also include the accounts of a variable interest entity (“VIE”) where the Company was the primary beneficiary of the arrangements during the year ended December 31, 2017. See Note 4 for additional information regarding the circumstances surrounding the VIE. The Company consolidates the financial statements of these entities. All material intercompany balances and transactions have been eliminated.

Reclassifications. Certain prior period amounts have been reclassified to conform to the 2017 presentation. These reclassifications had no impact on net income (loss), total stockholders’ equity or total cash flows.

Use of estimates in the preparation of financial statements. Preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates. Depletion of oil and natural gas properties is determined using estimates of proved oil and natural gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves, commodity price outlooks and prevailing market rates of other sources of income and costs. Other significant estimates include, but are not limited to, asset retirement obligations, fair value of stock-based compensation, fair value of business combinations, fair value of nonmonetary transactions, fair value of derivative financial instruments and income taxes.

Cash equivalents. The Company considers all cash on hand, depository accounts held by banks, money market accounts and investments with an original maturity of three months or less to be cash equivalents. The Company’s cash and cash equivalents are held in financial institutions in amounts that may exceed the insurance limits of the Federal Deposit Insurance Corporation. However, management believes that the Company’s counterparty risks are minimal based on the reputation and history of the institutions selected. At December 31, 2016, the majority of the Company’s cash was invested in stable value government money market funds.

Accounts receivable. The Company sells oil and natural gas to various customers and participates with other parties in the drilling, completion and operation of oil and natural gas wells. Oil and natural gas sales receivables related to these operations are generally unsecured. Joint interest receivables are generally secured pursuant to the operating agreement between or among the co-owners of the operated property. The Company determines joint interest operations accounts receivable allowances based on management’s assessment of the creditworthiness of the joint interest owners and the Company’s ability to realize the receivables through netting of anticipated future production revenues. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. The Company had an allowance for doubtful accounts of approximately $1 million for each of the years ended December 31, 2017 and 2016.

Inventory. Inventory consists primarily of tubular goods, water and other oilfield equipment that the Company plans to utilize in its ongoing exploration and development activities and is carried at the lower of cost or net realizable value, on a weighted average cost basis.

Oil and natural gas properties. The Company utilizes the successful efforts method of accounting for its oil and natural gas properties. Under this method all costs associated with productive wells and nonproductive development wells are capitalized, while nonproductive exploration costs are expensed. Capitalized leasehold costs relating to proved properties are depleted using the unit-of-production method based on proved reserves. The depletion of capitalized drilling and development costs and integrated assets is based on the unit-of-production method using proved developed reserves. During the years ended December 31, 2017, 2016 and 2015, the Company recognized depletion expense from operations of $1,122 million, $1,145 million and $1,203 million, respectively.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2017, 2016 and 2015

The Company generally does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets following the completion of drilling unless both of the following conditions are met:

(i) the well has found a sufficient quantity of reserves to justify its completion as a producing well; and

(ii) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the Company's large multi-well project development program, capital intensive nature and geographical location of certain projects, it may take longer than one year to evaluate the future potential of the exploration well and economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found proved reserves and is transferred to proved oil and natural gas properties or is noncommercial and is charged to exploration and abandonments expense. See Note 3 for additional information regarding the Company's suspended exploratory well costs.

Proceeds from the sales of individual properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depletion. Generally, no gain or loss is recognized until the entire depletion base is sold. However, gain or loss is recognized from the sale of less than an entire depletion base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the depletion base. Ordinary maintenance and repair costs are expensed as incurred.

Costs of significant nonproducing properties, wells in the process of being drilled and completed and development projects are excluded from depletion until the related project is completed. The Company capitalizes interest, if debt is outstanding, on expenditures for significant development projects until such projects are ready for their intended use. During the years ended December 31, 2017 and 2015, the Company had capitalized interest of approximately $3 million and $1 million, respectively. The Company did not have capitalized interest related to significant oil and natural gas development projects for the year ended December 31, 2016.

The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. The Company reviews its oil and natural gas properties by depletion base. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties and integrated assets would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved and risk-adjusted unproved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs and cash flows from integrated assets. The Company recognized impairment expense of approximately $1.5 billion and $61 million during the years ended December 31, 2016 and 2015, respectively, related to its proved oil and natural gas properties. The Company did not recognize impairment expense during the year ended December 31, 2017. See Note 7 for additional information regarding the Company's impairment expense.

Unproved oil and natural gas properties are periodically assessed for impairment by considering future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales and expiration of all or a portion of the projects. During the years ended December 31, 2017, 2016 and 2015, the Company recognized expense of approximately $29 million, $60 million and $35 million, respectively, related to abandoned and expiring acreage, which is included in exploration and abandonments expense in the accompanying consolidated statements of operations.

Other property and equipment. Other capital assets include buildings, transportation equipment, computer equipment and software, telecommunications equipment, leasehold improvements and furniture and fixtures. These items are recorded at cost, or fair value if acquired, and are depreciated using the straight-line method based on expected lives of the individual assets or group of assets ranging from two to 39 years. The Company had other capital assets of $234 million and $216 million, net of accumulated depreciation of $90 million and $74 million, at December 31, 2017 and December 31, 2016, respectively. During the years ended December 31, 2017, 2016 and 2015, the Company recognized depreciation expense of $21 million, $21 million and $19 million, respectively. During the year ended December 31, 2015, the Company had capitalized interest of approximately $1 million. The Company did not have capitalized interest related to other property and equipment

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2017, 2016 and 2015

during the years ended December 31, 2017 or 2016.

Funds held in escrow. At December 31, 2016, the Company's funds held in escrow totaled $43 million, which consisted of a deposit paid by the Company that was held in escrow for its Northern Delaware Basin acquisition. See Note 4 for additional information regarding the acquisition.

Deferred loan costs. Deferred loan costs are stated at cost, net of amortization, which is computed using the straight-line method. The Company had deferred loan costs related to its credit facility of $13 million and $11 million, net of accumulated amortization of $51 million and $56 million, in noncurrent assets at December 31, 2017 and 2016, respectively.

Intangible assets. The Company has capitalized certain rights acquired through acquisitions. The gross intangible assets, which have no residual value, are amortized over the estimated economic life of three to 25 years. Impairment will be assessed if indicators of potential impairment exist or when there is a material change in the remaining useful economic life. The following table reflects the gross and net intangible assets at December 31, 2017 and 2016, respectively:

	December 31,	
(in millions)	**2017**	**2016**
Gross intangibles	$ 42	$ 37
Accumulated amortization	(16)	(13)
Net intangibles	$ 26	$ 24

The Company recognized amortization expense of approximately $3 million for the year ended December 31, 2017 and approximately $1 million for each of the years ended December 31, 2016 and 2015. The Company will record amortization expense of approximately $3 million for the year ended December 31, 2018 and approximately $1 million for each of the remaining years under the term.

Equity method investments. Equity method investments are included in other assets in the Company's consolidated balance sheets. Income and losses incurred from the Company's equity investments are recorded in other income (expense) in its consolidated statements of operations.

At December 31, 2016, the Company owned a 50 percent membership interest in a midstream joint venture, Alpha Crude Connector, LLC ("ACC"), that constructed a crude oil gathering and transportation system in the Northern Delaware Basin. The Company's net investment in ACC was approximately $129 million at December 31, 2016. During the years ended December 31, 2016 and 2015, the Company recorded a loss of approximately $2 million and $4 million, respectively. In February 2017, the Company closed on the divestiture of its ownership interest in ACC. See Note 4 for additional information regarding the disposition of ACC.

The Company owns a membership interest in Oryx Southern Delaware Holdings, LLC ("Oryx"), an entity that operates a crude oil gathering and transportation system in the Southern Delaware Basin. During 2017, the Company's membership interest was reduced from 25 percent to 23.75 percent after the addition of a new partner. The Company's net investment was approximately $49 million and $42 million at December 31, 2017 and 2016, respectively. During the years ended December 31, 2017 and 2016, the Company recorded income of approximately $7 million and a loss of approximately $2 million, respectively.

Environmental. The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. At December 31, 2017 and 2016, the Company has accrued approximately $3 million and $1 million, respectively, related to environmental liabilities. During the years ended December 31, 2017, 2016 and 2015, the Company recognized environmental charges of approximately $9 million, $7 million and $3 million, respectively.

Senior note deferred loan costs. Senior note deferred loan costs are stated at cost, net of amortization, which is computed using the effective interest method. The Company had senior note deferred loan costs of $25 million and $31

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2017, 2016 and 2015

million, net of accumulated amortization of $1 million and $12 million, as a reduction of long-term debt at December 31, 2017 and 2016, respectively. See Note 9 for additional information regarding activity related to the Company's senior notes.

Income taxes. The Company recognizes deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company evaluates uncertain tax positions for recognition and measurement in the consolidated financial statements. To recognize a tax position, the Company determines whether it is more likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more likely than not threshold is measured to determine the amount of benefit to be recognized in the consolidated financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company had no material uncertain tax positions that required recognition in the consolidated financial statements at December 31, 2017 or 2016. Any interest or penalties would be recognized as a component of income tax expense.

On December 22, 2017, the President of the United States ("the President") signed into law the tax bill commonly referred to as the "Tax Cuts and Job Act" ("TCJA"), significantly changing federal income tax laws. According to the Accounting Standards Codification ("ASC") section 740, "Income Taxes," ("ASC 740"), a company is required to record the effects of an enacted tax law or rate change in the period of enactment, which is the date the bill is signed by the President and becomes law. As a result of the enactment of the TCJA, the U.S. Securities and Exchange Commission ("SEC") issued Staff Accounting Bulletin No. 118, "Income Tax Accounting Implications of the Tax Cuts and Jobs Act," ("SAB 118") to provide guidance for companies that have not completed the accounting for the income tax effects of the TCJA in the period of enactment. SAB 118 allows companies to report provisional amounts when based on reasonable estimates and to adjust these amounts during a measurement period of up to one year. The Company has elected to apply SAB 118 and, as such, has recorded provisional amounts for the income tax balances reported in its consolidated financial statements. The Company will continue to monitor any new administrative guidance or tax law interpretation. See Note 11 for additional information regarding the Company's deferred tax balances and its accounting for the impacts of the TCJA.

Derivative instruments. The Company recognizes its derivative instruments, other than any commodity derivative contracts that are designated as normal purchase and normal sale, as either assets or liabilities measured at fair value. The Company netted the fair value of derivative instruments by counterparty in the accompanying consolidated balance sheets where the right of offset exists. The Company does not have any derivatives designated as fair value or cash flow hedges. The Company may also enter into physical delivery contracts to effectively provide commodity price hedges. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the Company’s consolidated financial statements.

Asset retirement obligations. The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related asset is allocated to expense through depletion of the asset. Changes in the liability due to passage of time are generally recognized as an increase in the carrying amount of the liability and as corresponding accretion expense. Based on certain factors including commodity prices and costs, the Company may revise its previous estimates related to the liability, which would also increase or decrease the associated oil and natural gas property asset.

Treasury stock. Treasury stock purchases are recorded at cost.

Revenue recognition. Oil and natural gas revenues are recorded at the time of physical transfer of such products to the purchaser, which for the Company is primarily at the wellhead. The Company follows the sales method of accounting for oil and natural gas sales, recognizing revenues based on the Company’s actual proceeds from the oil and natural gas sold to purchasers.

Oil and natural gas imbalances. Oil and natural gas imbalances are generated on properties for which two or more owners have the right to take production “in-kind” and, in doing so, take more or less than their respective entitled percentage. Imbalances are tracked by well; however, the Company does not record any receivable from or payable to the other owners unless the imbalance has reached a level at which it exceeds the remaining reserves in the respective well. If reserves are insufficient to offset the imbalance and the Company is in an overtake position, a liability is recorded for the amount of shortfall

Concho Resources Inc.

Notes to Consolidated Financial Statements

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in reserves valued at a contract price or the market price in effect at the time the imbalance is generated. If the Company is in an undertake position, a receivable is recorded for an amount that is reasonably expected to be received, not to exceed the current market value of such imbalance. The Company had no significant imbalances at December 31, 2017 or 2016.

***General and administrative expense*.** The Company receives fees for the operation of jointly-owned oil and natural gas properties during the drilling and production phases and records such reimbursements as reductions of general and administrative expense. Such fees totaled approximately $16 million, $17 million and $19 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Stock-based compensation. Stock-based compensation expense is recognized in the Company's financial statements on an accelerated basis over the awards' vesting periods based on their grant date fair values. Stock-based compensation awards generally vest over a period ranging from one to eight years. The Company utilizes the average of the grant date's high and low stock prices for the fair value of restricted stock and the Monte Carlo simulation method for the fair value of performance unit awards.

Recently adopted accounting pronouncements. The Company adopted Accounting Standards Update ("ASU") No. 2016-09, "Compensation–Stock Compensations (Topic 718): Improvements to Employee Share-based Payment Accounting," on January 1, 2017. The adoption did not have an impact on prior period consolidated financial statements. The Company elected to account for forfeitures of share-based payments as they occur. At December 31, 2016, the Company had not recorded compensation expense of approximately $8 million based on forecasted forfeitures nor the associated deferred tax benefit of approximately $3 million. Additionally, the Company recognized all excess tax benefits not previously recorded, which totaled approximately $5 million at December 31, 2016. Upon adoption, the Company recorded a cumulative-effect adjustment, which decreased retained earnings by less than $1 million, increased additional paid-in capital by approximately $8 million, and decreased net deferred income tax liabilities by approximately $8 million. The Company elected to prospectively classify excess tax benefits and deficiencies as operating activities on the consolidated statements of cash flows and will prospectively record those excess tax benefits and deficiencies as discrete items in the income tax provision in the consolidated statements of operations. Under the new standard, for the year ended December 31, 2017, the Company recorded excess tax benefits of approximately $6 million in the Company's income tax provision. Also under the new standard, for the year ended December 31, 2017, the Company recorded actual forfeitures of share-based payments of approximately $8 million.

New accounting pronouncements issued but not yet adopted. In May 2014, the Financial Accounting Standards Board (the "FASB") issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," which outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. In August 2015, the FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date," which deferred the effective date of ASU No. 2014-09 by one year. That new standard is now effective for annual reporting periods beginning after December 15, 2017.

The Company has completed its evaluation and implementation of ASU No. 2014-09 and will adopt the new revenue recognition guidance during the first quarter of 2018. The Company has elected to use the modified retrospective method for adoption. Upon adoption, the Company will not record a material cumulative effect adjustment and prior period financial statements will not be restated. The adoption of this guidance is not expected to have an ongoing material impact on the Company's financial statements. More specifically, the adoption of this guidance will result in changes to sales of oil and natural gas and operating expenses due to the conclusion that some third-parties meet the definition of an agent under the control model in ASC 606, thus the fees paid to these service providers will be classified as operating expenses under ASC 606. With the adoption, the Company has updated its revenue recognition policy and its related internal control documentation, processes and controls to conform to the new standard. The Company will also expand its revenue recognition related disclosures.

In February 2016, the FASB issued ASU No. 2016-02, "Leases (Topic 842)," which supersedes current lease guidance. The new lease standard requires all leases with a term greater than one year to be recognized on the balance sheet while maintaining substantially similar classifications for financing and operating leases. Lease expense recognition on the consolidated statements of operations will be effectively unchanged. This guidance is effective for reporting periods beginning after December 15, 2018, and early adoption is permitted. The Company does not plan to early adopt the standard. The Company enters into lease agreements to support its operations. These agreements are for leases on assets such as office space, vehicles, field services, well equipment and drilling rigs. The Company is substantially complete with the process of reviewing and determining the contracts to which this new guidance applies. The Company is currently enhancing its accounting system in order to track and calculate additional information necessary for adoption of this standard. The Company believes this new guidance will have a moderate impact to its consolidated balance sheets due to the recognition of right-of-use assets and lease liabilities that are not currently recognized under currently applicable guidance.

In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments," which replaces the current "incurred loss" methodology for recognizing credit losses with an "expected loss" methodology. This new methodology requires that a financial asset measured at amortized cost be presented at the net amount expected to be collected. This standard is intended to provide more timely decision-useful information about the expected credit losses on financial instruments. This guidance is effective for fiscal years beginning after December 15, 2019, and early adoption is allowed as early as fiscal years beginning after December 15, 2018. The Company does not believe this new guidance will have a material impact on its consolidated financial statements.

In January 2017, the FASB issued ASU No. 2017-01, "Business Combinations (Topic 805): Clarifying the Definition of a Business," with the objective of adding guidance to assist in evaluating whether transactions should be accounted for as asset acquisitions or as business combinations. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the acquired assets is concentrated in a single asset or a group of similar assets, the set is not a business. If the screen is not met, to be considered a business, the set must include an input and a substantive process that together significantly contribute to the ability to create output. This new guidance is effective for annual periods beginning after December 15, 2017, and early adoption is allowed. The Company does not believe this new guidance will have a material impact on its consolidated financial statements.

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Note 3. ***Exploratory well costs***

The Company capitalizes exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. The capitalized exploratory well costs are carried in unproved oil and natural gas properties. See Unaudited Supplementary Data for the proved and unproved components of oil and natural gas properties. If the exploratory well is determined to be impaired, the well costs are charged to exploration and abandonments expense in the consolidated statements of operations.

The following table reflects the Company's net capitalized exploratory well activity during each of the years ended December 31, 2017, 2016 and 2015:

(in millions)	**Years Ended December 31, 2017**	**2016**	**2015**
Beginning capitalized exploratory well costs	$ 151	$ 116	$ 242
Additions to exploratory well costs pending the determination of proved reserves	180	144	103
Reclassifications due to determination of proved reserves	(147)	(86)	(228)
Exploratory well costs charged to expense	-	(6)	(1)
Disposition of wells	(2)	(17)	-
Ending capitalized exploratory well costs	$ 182	$ 151	$ 116

The following table provides an aging at December 31, 2017 and 2016 of capitalized exploratory well costs based on the date drilling was completed:

(in millions, except number of projects)	**December 31, 2017**	**2016**
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 180	$ 141
	2	10

Capitalized exploratory well costs that have been capitalized for a period greater than one year				
Total capitalized exploratory well costs	$	182	$	151
Number of projects with exploratory well costs that have been capitalized for a period greater				
than one year		2		8

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Note 4. ***Acquisitions, divestitures and nonmonetary transactions***

During the year ended December 31, 2017, the Company entered into the following transactions:

Northern Delaware Basin acquisition. In January and April 2017, the Company closed on the two-part acquisition in the Northern Delaware Basin. As consideration for the entire acquisition, the Company paid approximately $160 million in cash, of which $43 million was held in escrow at December 31, 2016, and issued to the seller approximately 2.2 million shares of its common stock with an approximate value of $291 million.

ACC divestiture. In February 2017, the Company closed on the divestiture of its ownership interest in ACC. The Company and its joint venture partner entered into separate agreements to sell 100 percent of their respective ownership interests in ACC. After adjustments for debt and working capital, the Company received cash proceeds from the sale of approximately $801 million. After direct transaction costs, the Company recorded a pre-tax gain on disposition of assets of approximately $655 million which is included in other income in the consolidated financial statements. The Company's net investment in ACC at the time of closing was approximately $129 million.

Midland Basin acquisition. In July 2017, the Company completed an acquisition in the Midland Basin. As consideration for the acquisition, the Company paid approximately $595 million in cash.

Concurrent with the acquisition, the Company entered into a transaction structured as a reverse like-kind exchange ("Reverse 1031 Exchange") in accordance with Section 1031 of the Internal Revenue Code of 1986, as amended (the "Code"). In connection with the Reverse 1031 Exchange, the Company assigned the ownership of the oil and natural gas properties acquired to a VIE formed by an exchange accommodation titleholder. The Company operates the properties pursuant to a management agreement with the VIE. At December 31, 2017, the Company was determined to be the primary beneficiary of the VIE, as the Company had the ability to control the activities that most significantly impact the VIE's economic performance. The assets currently held by the VIE attributable to the acquisition will be conveyed to the Company or one of its subsidiaries, and the VIE structure will terminate, upon the earlier of (i) the completion of the Reverse 1031 Exchange or (ii) the expiration of the time allowed by the treasury regulations and published Internal Revenue Service guidance to complete the Reverse 1031 Exchange, which is 180 days from commencement. At December 31, 2017, the VIE's total assets and liabilities included in the Company’s consolidated balance sheet were approximately $608 million and $604 million, respectively. See Note 17 for further discussion of the subsequent event that completed the Reverse 1031 Exchange.

Nonmonetary transactions. During 2017, the Company completed multiple nonmonetary transactions. The transactions include the exchange of both proved and unproved oil and natural gas properties. Certain of these transactions were accounted for at fair value and as a result the Company recorded pre-tax gains of approximately $26 million.

During the year ended December 31, 2016, the Company entered into the following transactions:

Asset divestiture. In February 2016, the Company sold certain assets in the northern Delaware Basin for proceeds of approximately $292 million and recognized a pre-tax gain of approximately $110 million.

Southern Delaware Basin acquisition. In March 2016, the Company completed an acquisition of 80 percent of a third-party seller’s interest in certain oil and natural gas properties and related assets in the southern Delaware Basin. As consideration for the acquisition, the Company issued to the seller approximately 2.2 million shares of common stock with an approximate value of $231 million, $146 million in cash and $40 million to carry a portion of the seller’s future development costs in these properties that was expended in 2016 and 2017 and included in costs incurred.

Reliance acquisition. In October 2016, the Company completed an acquisition of approximately 40,000 net acres in the northern Midland Basin and other assets from Reliance Energy, Inc. (collectively, the “Reliance Acquisition”) for approximately $1.7 billion. As consideration for the acquisition, the Company paid approximately $1.2 billion in cash and issued to the seller approximately 3.9 million shares of common stock with an approximate value of $0.5 billion.

Approximately $29 million of operating revenues and approximately $10 million of income from operations attributed to the Reliance Acquisition are included in the Company’s results of operations from the closing date in October 2016 through the year ended December 31, 2016.

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The following table reflects the fair value of the acquired assets and liabilities at the October 2016 closing date associated with the Reliance Acquisition:

(in millions)		
Fair value of net assets:		
Proved oil and natural gas properties	$	730
Unproved oil and natural gas properties		972
Other assets		34
Total assets acquired		1,736
Current liabilities, including current portion of asset retirement obligations		(8)
Asset retirement obligations assumed		(12)
Fair value of net assets acquired	$	1,716
Fair value of consideration paid for net assets:		
Cash consideration	$	1,176
Non-cash consideration, including equity		540
Total consideration paid for net assets	$	1,716

Pro forma data. The following unaudited pro forma combined condensed financial data for the year ended December 31, 2016 was derived from the historical financial statements of the Company giving effect to the Reliance Acquisition, as if it had occurred on January 1, 2016. The results of operations for the Reliance Acquisition are included in the Company's results of operations since the closing date in October 2016 through December 31, 2017. The pro forma financial data does not include the results of operations for any other acquisitions made during the periods presented, as they were primarily acreage acquisitions and their results were not deemed material. The unaudited pro forma combined condensed financial data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Reliance Acquisition taken place as of the date indicated and is not intended to be a projection of future results.

(in millions, except per share amounts)		**Year Ended December 31, 2016** (unaudited)
Operating revenues	$	1,717

Net loss	$	(1,396)
Earnings per common share:		
Basic net loss	$	(10.36)
Diluted net loss	$	(10.36)

During the year ended December 31, 2015, the Company entered into the following transaction:

Clayton Williams Acreage Exchange. In December 2015, the Company completed a nonmonetary acreage exchange with Clayton Williams Energy, Inc. that consolidated acres into a concentrated, operated position in the southern Delaware Basin. The Company recognized a loss on disposition of assets of approximately $50 million related to the acreage exchange based on the fair value of the assets surrendered.

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Note 5. *Asset retirement obligations*

The Company’s asset retirement obligations represent the estimated present value of the estimated cash flows the Company will incur to plug, abandon and remediate its producing properties at the end of their productive lives, in accordance with applicable state laws. Market risk premiums associated with asset retirement obligations are estimated to represent a component of the Company’s credit-adjusted risk-free rate that is utilized in the calculations of asset retirement obligations.

The Company’s asset retirement obligation transactions during the years ended December 31, 2017, 2016 and 2015 are summarized in the table below:

	Years Ended December 31,		
(in millions)	**2017**	**2016**	**2015**
Asset retirement obligations, beginning of period	$ 130	$ 120	$ 120
Liabilities incurred from new wells	2	2	4
Liabilities assumed in acquisitions	10	13	2
Accretion expense	8	7	8
Disposition of wells	(1)	(11)	-
Liabilities settled upon plugging and abandoning wells	(5)	(1)	(3)
Revision of estimates (a)	(3)	-	(11)
Asset retirement obligations, end of period	$ 141	$ 130	$ 120

(a) The revisions to the Company s asset retirement obligation estimates for the years ended December 31, 2017 and 2015 are primarily due to a reduction in the future estimated abandonment costs.

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Note 6. *Incentive plans*

Defined contribution plan. The Company sponsors a 401(k) defined contribution plan for the benefit of its employees. During the years ended December 31, 2017, 2016 and 2015, the Company matched 100 percent of employee contributions, not to exceed 10 percent of the employee's annual eligible compensation, subject to federal limits. The Company's contributions to the plan for the years ended December 31, 2017, 2016 and 2015 were approximately $10 million, $9 million and $10 million, respectively, of which a portion was recoverable from other working interest owners.

Stock incentive plan. The Company's 2015 Stock Incentive Plan (the "Plan") provides for granting stock options, restricted stock awards and performance awards to directors, officers and employees of the Company. A total of 10.5 million shares of common stock have been authorized for issuance under the Plan. At December 31, 2017, the Company had 2.1 million shares of common stock available for future grants. Shares issued as a result of awards granted under the Plan are generally new common shares.

Restricted stock awards. All restricted shares are legally issued and outstanding. If an employee terminates employment prior to the restriction lapse date, the awarded shares are forfeited and cancelled and are no longer considered issued and outstanding. A summary of the Company's restricted stock award activity for the year ended December 31, 2017 is presented below:

	Number of Restricted Shares	Weighted Average Grant Date Fair Value Per Share
Restricted stock:		
Outstanding at December 31, 2016	1,157,270	$ 115.29
Shares granted	490,300	$ 123.16
Shares cancelled / forfeited	(100,199)	$ 113.56
Lapse of restrictions	(398,125)	$ 117.91
Outstanding at December 31, 2017	1,149,246	$ 118.02

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For restricted stock awards granted, stock-based compensation expense is being recognized in the Company's consolidated financial statements on an accelerated basis over the awards' vesting periods based on their grant date fair values. The restricted stock-based compensation awards generally vest over a period ranging from one to eight years. The Company utilizes the average of the grant date's high and low stock prices for the fair value of restricted stock.

The following table summarizes information about stock-based compensation for the Company's restricted stock awards activity under the Plan for years ended December 31, 2017, 2016 and 2015:

	Years Ended December 31,		
(in millions)	**2017**	**2016**	**2015**
Fair value for awards granted during the period (a)	$ 60	$ 51	$ 50
Fair value for awards vested during the period	$ 49	$ 45	$ 36
Stock-based compensation expense from restricted stock	$ 43	$ 41	$ 43
Income tax benefit related to restricted stock	$ 11	$ 15	$ 16

(a) The weighted average grant date fair value per share amounts were $123.16, $112.78 and $109.76 for the years ended December 31, 2017, 2016 and 2015, respectively.

During the year ended December 31, 2017, the Company recorded actual forfeitures of $8 million which reduced total stock-based compensation expense. During the year ended December 31, 2016, the Company recorded $5 million of estimated forfeitures.

Stock option awards. A summary of the Company's stock option award activity under the Plan for the year ended December 31, 2017 is presented below:

	Number of Options	Weighted Average Exercise Price
Stock options:		
Outstanding at December 31, 2016	20,000	$ 15.33
Options exercised	(20,000)	$ 15.33
Outstanding at December 31, 2017	-	
Vested and exercisable at December 31, 2017	-	

The intrinsic value of options exercised was approximately $2 million for each of the years ended December 31, 2017 and 2016 based on the difference between the market price at the exercise date and the option exercise price. The Company did not have any material options exercised during the year ended December 31, 2015.

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Performance unit awards. During the years ended December 31, 2017, 2016 and 2015, the Company awarded performance units to its officers under the Plan. The number of shares of common stock that will ultimately be issued will be determined by a combination of (i) comparing the Company's total shareholder return relative to the total shareholder return of a predetermined group of peer companies at the end of the performance period and (ii) the Company's absolute total shareholder return at the end of the performance period. The performance period is 36 months. The grant date fair value was determined using the Monte Carlo simulation method and is being expensed ratably over the performance period. Expected volatilities utilized in the model were estimated using a historical period consistent with the remaining performance period of approximately three years. The risk-free interest rate was based on the U.S. Treasury rate for a term commensurate with the expected life of the grant.

The Company used the following assumptions to estimate the fair value of performance unit awards granted during the years ended December 31, 2017, 2016 and 2015:

	Years Ended December 31,		
	2017	**2016**	**2015**
Risk-free interest rate	1.47%	1.31%	1.07%
Range of volatilities	24.8% - 60.2%	31.6% - 59.0%	26.1% - 43.0%

The following table summarizes the performance unit activity for the year ended December 31, 2017:

	Number of Units		**Grant Date Fair Value**
Performance units:			
Outstanding at December 31, 2016	331,526	$	136.68
Units granted (a)	108,398	$	183.48
Units forfeited	(43,333)	$	140.00
Units vested (b)	(148,944)	$	156.86
Outstanding at December 31, 2017	247,647	$	146.10

(a) Reflects the amount of performance units granted. The actual payout of shares will be between zero and 300 percent of the performance units granted depending on the Company's performance at the end of the performance period.

(b) On December 31, 2017, the performance period ended for these performance units. Each unit converted into three shares representing 446,832 shares of common stock issued on January 2, 2018.

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The following table summarizes information about stock-based compensation expense for performance units for the years ended December 31, 2017, 2016 and 2015:

	Years Ended December 31,					
(in millions)		**2017**		**2016**		**2015**
Fair value for awards granted during the period (a)	$	20	$	19	$	28
Fair value for awards vested during the period	$	68	$	33	$	16
Stock-based compensation expense from performance units	$	17	$	18	$	20
Income tax benefit related to performance units	$	2	$	7	$	7

(a) The weighted average grant date fair value per unit amounts were $183.48, $114.81 and $156.86 for the years ended December 31, 2017, 2016 and 2015, respectively.

Future stock-based compensation expense. The following table reflects the future stock-based compensation expense to be recorded for all the stock-based compensation awards that were outstanding at December 31, 2017:

(in millions)		
2018	$	49
2019		26
2020		8
Thereafter		2
Total	$	85

Note 7. ***Disclosures about fair value measurements***

The Company uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following fair value input hierarchy:

Level 1**:** Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. The Company considers active markets to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2**:** Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that the Company values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Level 2 instruments primarily include non-exchange traded derivatives such as over-the-counter commodity price swaps, basis swaps, collars and floors, investments and interest rate swaps. The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) current market and contractual prices for the underlying instruments and (iv) volatility factors, as well as other relevant economic measures.

Level 3**:** Prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (*i.e.*, supported by little or no market activity). The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) volatility factors and (iv) current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

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Financial Assets and Liabilities Measured at Fair Value

The following table presents the carrying amounts and fair values of the Company's financial instruments at December 31, 2017 and 2016:

(in millions)	December 31, 2017 Carrying Value	December 31, 2017 Fair Value	December 31, 2016 Carrying Value	December 31, 2016 Fair Value
Assets:				
Derivative instruments	$ -	$ -	$ 4	$ 4
Liabilities:				
Derivative instruments	$ 379	$ 379	$ 178	$ 178
Credit facility	$ 322	$ 322	$ -	$ -
$600 million 5.5% senior notes due 2022 (a)	$ -	$ -	$ 594	$ 620
$1,550 million 5.5% senior notes due 2023 (a)	$ -	$ -	$ 1,555	$ 1,621
$600 million 4.375% senior notes due 2025 (a)	$ 593	$ 624	$ 592	$ 599
$1,000 million 3.75% senior notes due 2027 (a)	$ 987	$ 1,012	$ -	$ -
$800 million 4.875% senior notes due 2047 (a)	$ 789	$ 874	$ -	$ -

(a) The carrying value includes associated deferred loan costs and any premium (discount).

Credit facility. The carrying amount of the Company's credit facility approximates its fair value, as the applicable interest rates are variable and reflective of market rates.

Senior notes. The fair values of the Company's senior notes are based on quoted market prices. The debt securities are not actively traded and, therefore, are classified as Level 2 in the fair value hierarchy.

Other financial assets and liabilities. The Company has other financial instruments consisting primarily of receivables, payables and other current assets and liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

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Derivative instruments. The fair value of the Company's derivative instruments is estimated by management considering various factors, including closing exchange and over-the-counter quotations and the time value of the underlying commitments. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The following tables summarize (i) the valuation of each of the Company's financial instruments by required fair value hierarchy levels and (ii) the gross fair value by the appropriate balance sheet classification, even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the Company's consolidated balance sheets atDecember 31, 2017 and 2016. The Company nets the fair value of derivative instruments by counterparty in the Company's consolidated balance sheets.

	December 31, 2017					
	Fair Value Measurements Using					Net
(in millions)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Fair Value Presented in the Consolidated Balance Sheet
Assets						
Current:						
Commodity derivatives	$ -	$ 13	$ -	$ 13	$ (13)	$ -
Noncurrent:						
Commodity derivatives	-	1	-	1	(1)	-
Liabilities						
Current:						
Commodity derivatives	-	(290)	-	(290)	13	(277)
Noncurrent:						
Commodity derivatives	-	(103)	-	(103)	1	(102)

Net derivative instruments	$	-	$	(379)	$	-	$	(379)	$	-	$ (379)

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	December 31, 2016					
	Fair Value Measurements Using					Net
(in millions)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Fair Value Presented in the Consolidated Balance Sheet
Assets						
Current:						
Commodity derivatives	$ -	$ 59	$ -	$ 59	$ (55)	$ 4
Noncurrent:						
Commodity derivatives	-	-	-	-	-	-
Liabilities						
Current:						
Commodity derivatives	-	(137)	-	(137)	55	(82)
Noncurrent:						
Commodity derivatives	-	(96)	-	(96)	-	(96)
Net derivative instruments	$ -	$ (174)	$ -	$ (174)	$ -	$ (174)

Concentrations of credit risk. At December 31, 2017, the Company's primary concentrations of credit risk are the risk of collecting accounts receivable and the risk of counterparties' failure to perform under derivative obligations. See Note 12 for information regarding the Company's major customers and derivative counterparties.

The Company has entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of its derivative counterparties. The terms of the ISDA Agreements provide the

Company and the counterparties with rights of set-off upon the occurrence of defined acts of default by either the Company or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note 8 for additional information regarding the Company's derivative activities.

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Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in the Company’s consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Impairments of long-lived assets – The Company periodically reviews its long-lived assets to be held and used, including proved oil and natural gas properties and their integrated assets, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. The Company reviews its oil and natural gas properties by depletion base. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of the Company’s assets, it recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

The Company calculates the expected undiscounted future net cash flows of its long-lived assets and their integrated assets using management’s assumptions and expectations of (i) commodity prices, which are based on the New York Mercantile Exchange (“NYMEX”) strip, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, and (vii) prevailing market rates of income and expenses from integrated assets. At December 31, 2017, the Company’s estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2018 price of $59.55 per barrel of oil decreasing to a 2024 price of $51.82 per barrel of oil marginally recovering to a 2025 price of $51.83 per barrel of oil. Similarly, natural gas prices ranged from a 2018 price of $2.84 per Mcf of natural gas decreasing to a 2019 price of $2.81 per Mcf then rising to a 2025 price of $2.99 per Mcf of natural gas. Both oil and natural gas commodity prices for this purpose were held flat after 2025. The Company did not recognize any impairment loss during the year ended December 31, 2017.

The Company calculates the estimated fair values of its long-lived assets and their integrated assets using a discounted future cash flow model. Fair value assumptions associated with the calculation of discounted future net cash flows include (i) market estimates of commodity prices, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, (vii) prevailing market rates of income and expenses from integrated assets and (viii) discount rate. The expected future net cash flows were discounted using an annual rate of 10 percent to determine fair value. These are classified as Level 3 fair value assumptions.

During the three months ended March 31, 2016, NYMEX strip prices declined as compared to December 31, 2015, and as a result the carrying amount of the Company's Yeso field of approximately $3.4 billion exceeded the expected undiscounted future net cash flows resulting in a non-cash charge against earnings of approximately $1.5 billion. The non-cash charge represented the amount by which the carrying amount exceeded the estimated fair value of the assets.

The following table reports the carrying amount, estimated fair value and impairment expense of long-lived assets for the indicated periods:

(in millions)	**Carrying Amount**	**Estimated Fair Value (Level 3)**	**Impairment Expense**
March 2016	$ 3,438	$ 1,913	$ 1,525
December 2015	$ 105	$ 52	$ 53
September 2015	$ 18	$ 10	$ 8

It is reasonably possible that the estimate of undiscounted future net cash flows of the Company's long-lived assets may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future cash flows are (i) commodity prices including differentials, (ii) increases or decreases in production and capital costs, (iii) future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities and (v) changes in income and expenses from integrated assets.

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Note 8. *Derivative financial instruments*

The Company uses derivative financial instruments to manage its exposure to commodity price fluctuations. Commodity derivative instruments are used to (i) reduce the effect of the volatility of price changes on the oil and natural gas the Company produces and sells, (ii) support the Company's capital budget and expenditure plans and (iii) support the economics associated with acquisitions. The Company does not enter into derivative financial instruments for speculative or trading purposes. The Company also enters into fixed-price forward physical power purchase contracts to manage the volatility of the price of power needed for ongoing operations. The Company may also enter into physical delivery contracts to effectively provide commodity price hedges. Because these physical contracts are not expected to be net cash settled, the Company has elected normal purchase or normal sale treatment and are thus recorded at cost.

The Company does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Company reflects changes in the fair value of its derivative instruments in its consolidated statements of operations as they occur.

The following table summarizes the amounts reported in earnings related to the commodity derivative instruments for the years ended December 31, 2017, 2016 and 2015:

	Years Ended December 31,		
(in millions)	**2017**	**2016**	**2015**
Gain (loss) on derivatives:			
Oil derivatives	$ (172)	$ (337)	$ 675
Natural gas derivatives	46	(32)	25
Total	$ (126)	$ (369)	$ 700

The following table represents the Company's net cash receipts from derivatives for the years ended December 31, 2017, 2016 and 2015:

	Years Ended December 31,		
(in millions)	2017	2016	2015
Net cash receipts from derivatives:			
Oil derivatives	$ 79	$ 609	$ 597
Natural gas derivatives	-	16	36
Total	$ 79	$ 625	$ 633

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Commodity derivative contracts at December 31, 2017. The following table sets forth the Company's outstanding derivative contracts at December 31, 2017. When aggregating multiple contracts, the weighted average contract price is disclosed. All of the Company's derivative contracts at December 31, 2017 are expected to settle by December 31, 2019.

		First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Price Swaps: (a)						
2018:						
Volume (Bbl)		10,123,629	8,965,170	7,931,318	7,432,007	34,452,124
Price per Bbl	$	52.05$	51.92$	51.65$	51.57$	51.82
2019:						
Volume (Bbl)		6,613,000	6,254,500	5,946,000	5,681,000	24,494,500
Price per Bbl	$	52.36$	52.33$	52.37$	52.36$	52.35
Oil Basis Swaps: (b)						
2018:						
Volume (Bbl)		10,059,000	8,855,000	8,066,000	7,451,000	34,431,000
Price per Bbl	$	(0.80)$	(0.88)$	(0.89)$	(0.93)$	(0.87)
2019:						
Volume (Bbl)		6,870,000	6,505,500	6,210,000	5,933,000	25,518,500
Price per Bbl	$	(0.96)$	(0.98)$	(0.99)$	(1.01)$	(0.98)
Natural Gas Price Swaps: (c)						
2018:						
Volume (MMBtu)		16,556,000	16,101,000	14,819,000	14,504,000	61,980,000
Price per MMBtu	$	3.05$	3.04$	3.04$	3.03$	3.04
2019:						
Volume (MMBtu)		4,591,533	4,501,387	4,418,537	4,329,535	17,840,992
Price per MMBtu	$	2.86$	2.86$	2.86$	2.86$	2.86

(a) The index prices for the oil price swaps are based on the NYMEX – West Texas Intermediate ("WTI") monthly average futures price.
(b) The basis differential price is between Midland – WTI and Cushing – WTI.

(c) The index prices for the natural gas price swaps are based on the NYMEX – Henry Hub last trading day futures price.

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the creditworthiness of counterparties to its derivative instruments. The Company believes that all of its derivative counterparties are currently acceptable credit risks. The Company is not required to provide credit support or collateral to any counterparties under its derivative contracts, nor are they required to provide credit support to the Company. In September 2017, the Company elected to enter into an “Investment Grade Period” under the Credit Facility, as defined below, which had the effect of releasing all collateral formerly securing the Credit Facility. Additionally, as a result of the Company’s Investment Grade Period election along with amendments to certain ISDA Agreements with the Company’s derivative counterparties, the Company’s derivatives are no longer secured. See Note 9 for additional information regarding the Credit Facility.

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Note 9. ***Debt***

The Company's debt consisted of the following at December 31, 2017 and 2016:

	December 31,	
(in millions)	**2017**	**2016**
Credit facility	$ 322	$ -
5.5% unsecured senior notes due 2022	-	600
5.5% unsecured senior notes due 2023	-	1,550
4.375% unsecured senior notes due 2025 (a)	600	600
3.75% unsecured senior notes due 2027	1,000	-
4.875% unsecured senior notes due 2047	800	-
Unamortized original issue premium (discount), net	(6)	22
Senior notes issuance costs, net	(25)	(31)
Less: current portion	-	-
Total long-term debt	$ 2,691	$ 2,741

(a) For each of the twelve month periods beginning on January 15, 2020, 2021, 2022, 2023 and thereafter, these notes are callable at 103.281%, 102.188%, 101.094% and 100%, respectively.

Credit facility. The Company's credit facility, as amended and restated (the "Credit Facility"), has a maturity date of May 9, 2022. At December 31, 2017, the Company's commitments from its bank group were $2.0 billion.

In April 2017, the Company amended the Credit Facility to extend the maturity date, increase the borrowing base and decrease unused lender commitments. The amendment also lowered the corporate ratings floor sufficient to automatically terminate an Investment Grade Period under the Credit Facility from (i) "Ba1" to "Ba2" for Moody's Investors Service, Inc. ("Moody's") and (ii) "BB+" to "BB" for S&P Global Ratings ("S&P").

The Company recorded a loss on extinguishment of debt of approximately $1 million for the proportional amount of unamortized deferred loan costs associated with banks that are no longer in the Credit Facility syndicate as a result of the April 2017 amendment.

In September 2017, the Company elected to enter into an Investment Grade Period under the Credit Facility, which had the effect of releasing all collateral formerly securing the Credit Facility. If the Investment Grade Period under the Credit Facility terminates (whether automatically due to a downgrade of the Company's credit ratings below certain thresholds or by the Company's election), the Credit Facility will once again be secured by a first lien on substantially all of the Company's oil and natural gas properties and by a pledge of the equity interests in its subsidiaries. At December 31, 2017, certain of the Company's 100 percent owned subsidiaries are guarantors under the Credit Facility.

During an Investment Grade Period, advances on the Credit Facility bear interest, at the Company's option, based on (i) an alternative base rate, which is equal to the highest of (a) the prime rate of JPMorgan Chase Bank (4.50 percent at December 31, 2017), (b) the federal funds effective rate plus 0.5 percent and (c) the London Interbank Offered Rate ("LIBOR") plus 1.0 percent or (ii) LIBOR. The Credit Facility's interest rates and commitment fees on the unused portion of the available commitment vary depending on the Company's credit ratings from Moody's and S&P. At the Company's current credit ratings, LIBOR Rate Loans and Alternate Base Rate Loans bear interest margins of 150 basis points and 50 basis points per annum, respectively, and commitment fees on the unused portion of the available commitment are 25 basis points per annum. During the years ended December 31, 2017, 2016 and 2015, the Company incurred commitment fees on the unused portion of the available commitments of $6 million, $8 million and $7 million, respectively. The Company had $1.7 billion of unused commitments under the Credit Facility at December 31, 2017.

The Credit Facility contains various restrictive covenants and compliance requirements, which include:

• maintenance of certain financial ratios, including maintenance of a quarterly ratio of consolidated total debt to consolidated earnings, as defined, before interest expense, income taxes, depletion, depreciation, and

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amortization, exploration expense and other non-cash income and expenses to be no greater than 4.25 to 1.0, and during an Investment Grade Period, if the Company does not have both a rating of “Baa3” or better from Moody’s and a rating of “BBB-” or better from S&P, maintenance of a quarterly ratio of PV-9 of the Company’s oil and natural gas properties reflected in its most recently delivered reserve report to consolidated total debt to be no less than 1.50 to 1.0;

- limits on the incurrence of additional indebtedness and certain types of liens;

- restrictions as to mergers, combinations and dispositions of assets; and

- restrictions on the payment of cash dividends.

Senior notes. Interest on the Company’s senior notes is paid in arrears semi-annually. The senior notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of the Company’s 100 percent owned subsidiaries, subject to customary release provisions as described in Note 16.

In September 2017, the Company issued $1,800 million in aggregate principal amount of unsecured senior notes, consisting of $1,000 million in aggregate principal amount of 3.75% unsecured senior notes due 2027 (the “3.75% Notes”) and $800 million in aggregate principal amount of 4.875% unsecured senior notes due 2047 (the “4.875% Notes” and, together with the 3.75% Notes, the “2017 Notes”). The 3.75% Notes were issued at a price equal to 99.636 percent of par, and the 4.875% Notes were issued at a price equal to 99.749 percent of par. The Company received net proceeds of approximately $1,777 million.

Additionally, in September 2017, the Company completed a cash tender offer (the “Tender Offer”) to purchase any and all of the outstanding $600 million aggregate principal amount of its 5.5% unsecured senior notes due 2022 and the outstanding $1,550 million aggregate principal amount of its 5.5% unsecured senior notes due 2023 (collectively, the “5.5% Notes”). The Company received tenders from the holders of approximately $1,232 million in aggregate principal amount, or approximately 57.3 percent, of its outstanding 5.5% Notes in connection with the Tender Offer at a price of 102.934 percent of the unpaid principal amount plus accrued and unpaid interest to the settlement date.

In connection with the Tender Offer, the Company redeemed the remaining outstanding 5.5% Notes not purchased in the Tender Offer at a price, including the make-whole premium as determined in accordance with the indentures, of 102.75 percent of the unpaid principal amount plus accrued and unpaid interest. Additionally in September 2017, the Company completed a satisfaction and discharge of the redeemed notes, where the Company prepaid interest to October 13, 2017. The Company used the net proceeds from the offering of the 2017 Notes, together with cash on hand and borrowings under its Credit Facility, to fund the Tender Offer and the satisfaction and discharge of its obligations under the indentures of the 5.5% Notes.

In December 2016, the Company issued $600 million in aggregate principal amount of 4.375% senior notes due 2025 at par, for which it received net proceeds of approximately $592 million. The Company used the net proceeds from the offering to fund the satisfaction and discharge of its obligations under the indenture of the $600 million outstanding principal amount of its 6.5% unsecured senior notes due 2022 (the “6.5% Notes”) at a price equal to 103.25 percent of par. The early extinguishment price included the make-whole premium as determined in accordance with the indenture governing the 6.5% Notes. In December 2016, the Company also paid interest of approximately $20 million on the 6.5% Notes through January 16, 2017.

The Company recorded a loss on extinguishment of debt related to the 6.5% Notes of approximately $28 million for the year ended December 31, 2016. This amount includes $20 million associated with the make-whole premium paid for the early extinguishment of the notes, approximately $7 million of unamortized deferred loan costs and approximately $1 million of additional interest on the 6.5% Notes through January 16, 2017, which was paid in December 2016.

In September 2016, the Company redeemed the $600 million outstanding principal amount of its 7.0% unsecured senior notes due 2021 (the “7.0% Notes”) at a price equal to 103.5 percent of par. The redemption price included the make-whole premium for the early redemption, as determined in accordance with the indenture governing the 7.0% Notes. The Company also paid accrued and unpaid interest on the 7.0% Notes through September 19, 2016, the redemption date.

The Company recorded a loss on extinguishment of debt related to the redemption of the 7.0% Notes of approximately $28 million for the year ended December 31, 2016. This amount includes $21 million associated with the make-whole premium paid for the early redemption of the notes and approximately $7 million of unamortized deferred loan costs.

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As a result of the transactions discussed above, the Company recorded a loss on extinguishment of debt for the year ended December 31, 2017 as follows:

(in millions)	Credit Facility April 2017 Amendment	Senior Notes September 2017 Tender Offer	Senior Notes September 2017 Extinguishment	Total
Cash:				
Tender premium	$ -	$ 36	$ -	$ 36
Make-whole premium	-	-	25	25
Prepaid interest	-	-	2	2
Total cash	-	36	27	63
Non-cash:				
Unamortized original issue premium	-	(11)	(8)	(19)
Unamortized deferred loan costs	1	12	9	22
Total non-cash	1	1	1	3
Total loss on extinguishment of debt	$ 1	$ 37	$ 28	$ 66

At December 31, 2017, the Company was in compliance with the covenants under all of its debt instruments.

Principal maturities of long-term debt. Principal maturities of long-term debt outstanding at December 31, 2017 were as follows:

(in millions)	
2018	$ -
2019	-
2020	-
2021	-

2022		322
Thereafter		2,400
Total	$	2,722

Interest expense. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2017, 2016 and 2015:

	Years Ended December 31,		
(in millions)	**2017**	**2016**	**2015**
Cash payments for interest	$ 139	$ 232	$ 211
Non-cash interest	6	9	9
Net changes in accruals	4	(37)	-
Interest costs incurred	149	204	220
Less: capitalized interest	(3)	-	(5)
Total interest expense	$ 146	$ 204	$ 215

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Note 10. *Commitments and contingencies*

Severance agreements. The Company has entered into severance and change in control agreements with all of its officers. The current annual salaries for the Company's officers covered under such agreements total approximately $8 million.

Indemnifications. The Company has agreed to indemnify its directors and officers with respect to claims and damages arising from certain acts or omissions taken in such capacity.

Legal actions. The Company is a party to proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to any such proceedings or claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future results of operations. The Company will continue to evaluate proceedings and claims involving the Company on a regular basis and will establish and adjust any reserves as appropriate to reflect its assessment of the then current status of the matters.

Severance tax, royalty and joint interest audits. The Company is subject to routine severance, royalty and joint interest audits from regulatory bodies and non-operators and makes accruals as necessary for estimated exposure when deemed probable and estimable. Additionally, the Company is subject to various possible contingencies that arise primarily from interpretations affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, allowable costs under joint interest arrangements and other matters. At December 31, 2016, the Company had $7 million accrued for estimated exposure that has since been satisfied. Although the Company believes that it has estimated its exposure with respect to the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued.

Commitments. The Company periodically enters into contractual arrangements under which the Company is committed to expend funds. These contractual arrangements relate to purchase agreements the Company has entered into including drilling commitments, water commitment agreements, throughput volume delivery commitments, power commitments, fixed asset commitments and maintenance commitments. The following table summarizes the Company's commitments atDecember 31, 2017:

(in millions)		
2018	$	33
2019		51
2020		33
2021		29
2022		26
Thereafter		84
Total	$	256

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Operating leases. The Company leases vehicles, equipment and office facilities under non-cancellable operating leases. Lease payments associated with these operating leases for the year ended December 31, 2017 was approximately $10 million and approximately $8 million for each of the years ended December 31, 2016 and 2015, respectively.

Future minimum lease commitments under non-cancellable operating leases at December 31, 2017 were as follows:

(in millions)		
2018	$	10
2019		8
2020		7
2021		5
2022		-
Thereafter		1
Total	$	31

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Note 11. ***Income taxes***

The Company uses an asset and liability approach for financial accounting and reporting for income taxes. The Company's objectives of accounting for income taxes are to recognize (i) the amount of taxes payable or refundable for the current year and (ii) deferred tax liabilities and assets for the future tax consequences of events that have been recognized in its financial statements or tax returns. The Company and its subsidiaries file a federal corporate income tax return on a consolidated basis. The tax returns and the amount of taxable income or loss are subject to examination by federal and state taxing authorities.

On December 22, 2017, the President signed into law the TCJA, which enacted significant changes to federal income tax laws, including a decrease in the federal corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018. In accordance with the guidance stated in ASC 740, "Income Taxes," the Company is required to account for the effects of an enacted tax law or rate change in the period of enactment, which is the date it is signed by the President. Set forth below is a discussion of certain provisions enacted by the TCJA and the Company's assessment of the impact of such provisions on its consolidated results.

In accordance with SAB 118, the Company has calculated its best estimate of the impact of the TCJA, including the federal statutory tax rate change noted above, in accordance with its understanding of the TCJA and guidance available as of the date of this filing and as a result has recorded $398 million as a decrease to its income tax provision at December 31, 2017. The provisional amount related to the re-measurement of certain deferred tax assets and liabilities, based on the rates at which they are expected to reverse in the future, was $398 million.

The TCJA also repealed the corporate alternative minimum tax ("AMT") for tax years beginning after December 31, 2017, and provides that existing AMT credit carryovers are refundable beginning with the 2018 tax year. The Company has approximately $10 million of AMT credit carryovers that are expected to be fully refunded by 2022. At December 31, 2017, the Company had current income tax receivables of approximately $5 million.

At December 31, 2017, the Company did not have any significant uncertain tax positions requiring recognition in the financial statements. The tax years 2013 through 2017 remain subject to examination by the major tax jurisdictions.

The Company’s income tax expense (benefit) attributable to income (loss) from operations consisted of the following for the years ended December 31, 2017, 2016 and 2015:

	Years Ended December 31,		
(in millions)	**2017**	**2016**	**2015**
Current:			
U.S. federal	$ (6)	$ (12)	$ -
U.S. state and local	2	-	1
Total current income tax expense (benefit)	(4)	(12)	1
Deferred:			
U.S. federal	(94)	(771)	40
U.S. state and local	23	(93)	(10)
Total deferred income tax expense (benefit)	(71)	(864)	30
Total income tax expense (benefit) attributable to income from operations	$ (75)	$ (876)	$ 31

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The reconciliation between the income tax expense (benefit) computed by multiplying pre-tax income (loss) from operations by the U.S. federal statutory rate and the reported amounts of income tax expense (benefit) from operations is as follows:

	Years Ended December 31,		
(in millions)	**2017**	**2016**	**2015**
Income (loss) at U.S. federal statutory rate	$ 308	$ (818)	$ 34
Provisional change in deferred tax assets and liabilities	(398)	-	-
State income taxes, net of federal tax effect	17	(41)	3
Revisions of previous estimates	-	1	(1)
Change in estimated effective statutory state income tax	-	(21)	(9)
Excess tax benefit related to stock-based compensation	(6)	-	-
Nondeductible expense and other	4	3	4
Income tax expense (benefit)	$ (75)	$ (876)	$ 31
Effective tax rate	(9)%	38%	32%

The Company monitors changes in enacted tax rates for the jurisdictions in which it operates. The Company monitors its state tax apportionment footprint and makes updates for changes in its projected activity, including changes in budgets and drilling plans. During 2013, the State of New Mexico passed legislation to phase in a tax rate reduction over the next five years. In June of 2015, the State of Texas enacted legislation to reduce its rate. Based upon the Company's projected future activity for the states in which it conducts business, the timing for when it anticipates its deferred tax items to become taxable and enacted tax rates at such time deferred items become taxable, the Company did not revise its estimated state rate and, as such, did not record an additional deferred state tax benefit during 2017. The Company did revise its estimated state rate and recorded an additional deferred state tax benefit of approximately $21 million and $9 million during 2016 and 2015, respectively.

The Company recorded a discrete income tax benefit of approximately $6 million for the year ended December 31, 2017 related to excess tax benefits on stock-based awards, which is recorded in the income tax provision pursuant to ASU No. 2016-09 adopted on January 1, 2017.

The Company’s 2017 effective tax rate decreased as compared to 2016 primarily due to the provisional $398 million income tax benefit recognized as a result of the re-measurement of the Company’s net deferred tax liability based on changes enacted by the TCJA. This benefit more than offset the $308 million income tax expense on income before income taxes during 2017 at the federal statutory rate.

The Company’s effective tax rate increased in 2016 as compared to 2015 primarily due to a shift from pre-tax earnings of $97 million in 2015 to a pre-tax loss of $2.3 billion in 2016, resulting in a less pronounced effect on the effective tax rate for each reconciling item. In particular, the reduction in the Company’s effective statutory state rate caused a 1 percent increase in 2016 as compared to a 9 percent reduction in 2015, partially offset by other reconciling and non-deductible items for a net rate increase of 5 percent over 2015.

At December 31, 2016, the Company had approximately $539 million of federal net operating losses (“NOLs”), of which $6 million was carried back to the 2014 tax year. During 2017, the Company projects it will utilize approximately $411 million of the remaining NOLs available of $533 million. At December 31, 2017, the Company had approximately $122 million of NOLs that will expire in 2036 but are allowable as a deduction against 100 percent of future taxable income since they were generated prior to the effective date of limitations imposed by the TCJA. Additionally, the Company has estimated an apportioned New Mexico NOL of approximately $111 million expiring in 2036.

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The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities were as follows:

	December 31,	
(in millions)	**2017**	**2016**
Deferred tax assets:		
Stock-based compensation	$ 18	$ 39
Derivative instruments	87	64
Asset retirement obligation	33	48
Net operating losses and credits	31	177
Other	13	24
Total deferred tax assets	182	352
Deferred tax liabilities:		
Oil and natural gas properties, principally due to differences in basis and depreciation and the deduction of intangible drilling costs for tax purposes	(852)	(1,095)
Intangible assets	(5)	(9)
Other	(12)	(14)
Total deferred tax liability	(869)	(1,118)
Net deferred tax liability	$ (687)	$ (766)

The Company had net deferred tax liabilities of approximately $687 million and $766 million as of December 31, 2017 and 2016, respectively.

Pursuant to management's assessment, the Company does not believe a cumulative ownership change has occurred as of December 31, 2017. As such, Section 382 of the Internal Revenue Code of 1986, as amended, is not expected to limit the Company's ability to utilize its NOL carryforward as of December 31, 2017.

Management monitors company-specific, oil and natural gas industry and worldwide economic factors and assesses the likelihood that the Company's NOLs and other deferred tax attributes will be utilized prior to their expiration. At December 31, 2017, management considered all factors including the expected reversal of deferred tax liabilities (including the impact of available carryback and carryforward periods), historical operating income tax planning strategies and projected future taxable income. Based on the results of the assessment, management determined that it is more likely than not that the Company will realize its deferred tax assets.

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Note 12. *Major customers and derivative counterparties*

Sales to major customers. The Company's share of oil and natural gas production is sold to various purchasers. The Company is of the opinion that the loss of any one purchaser would not have a material adverse effect on the ability of the Company to sell its oil and natural gas production.

The following purchasers individually accounted for 10 percent or more of the consolidated oil and natural gas revenues during the years ended December 31, 2017, 2016 and 2015:

	Years Ended December 31,		
	2017	**2016**	**2015**
Plains Marketing and Transportation, Inc.	21%	29%	11%
Holly Frontier Refining and Marketing, LLC	10%	16%	25%
Enterprise Crude Oil LLC	8%	7%	12%

At December 31, 2017, the Company had receivables from Plains Marketing & Transportation Inc., Holly Frontier Refining and Marketing, LLC and Enterprise Crude Oil LLC of $72 million, $36 million and $30 million, respectively, which are reflected in accounts receivable — oil and natural gas in the accompanying consolidated balance sheets.

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the creditworthiness of counterparties to its derivative instruments. The Company believes that all of its derivative counterparties are currently acceptable credit risks. The Company is not required to provide credit support or collateral to any counterparties under its derivative contracts, nor are they required to provide credit support to the Company. In September 2017, the Company elected to enter into an "Investment Grade Period" under the Credit Facility, which had the effect of releasing all collateral formerly securing the Credit Facility. Additionally, as a result of the Company's Investment Grade Period election along with amendments to certain ISDA Agreements with the Company's derivative counterparties, the Company's derivatives are no longer secured. See Note 9 for additional information regarding the Credit Facility.

Note 13. ***Related party transactions***

The Company paid royalties on certain properties to a partnership in which a director of the Company is the general partner and owns a 3.5 percent partnership interest. These payments were reported in the Company's consolidated statements of operations and totaled approximately $7 million, $4 million and $6 million for the years ended December 31, 2017, 2016 and 2015, respectively.

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Note 14. *Earnings per share*

The Company uses the two-class method of calculating earnings per share because certain of the Company's unvested share-based awards qualify as participating securities.

The Company's basic earnings per share attributable to common stockholders is computed as (i) net income (loss) as reported, (ii) less participating basic earnings (iii) divided by weighted average basic common shares outstanding. The Company's diluted earnings per share attributable to common stockholders is computed as (i) basic earnings attributable to common stockholders, (ii) plus reallocation of participating earnings (iii) divided by weighted average diluted common shares outstanding.

The following table reconciles the Company's earnings from operations and earnings attributable to common stockholders to the basic and diluted earnings used to determine the Company's earnings per share amounts for the years ended December 31, 2017, 2016 and 2015, respectively, under the two-class method:

(in millions, except per share amounts)	**Years Ended December 31, 2017**	**2016**	**2015**
Net income (loss) as reported	$ 956	$ (1,462)	$ 66
Participating basic earnings (a)	(7)	-	(1)
Basic earnings attributable to common stockholders	949	(1,462)	65
Reallocation of participating earnings	-	-	-
Diluted earnings attributable to common stockholders	$ 949	$ (1,462)	$ 65

(a) Unvested restricted stock awards represent participating securities because they participate in nonforfeitable dividends or distributions with the common equity holders of the Company. Participating earnings represent the distributed earnings of the Company attributable to the participating securities. Unvested restricted stock awards do not participate in undistributed net losses as they are not contractually obligated to do so.

The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the years ended December 31, 2017, 2016 and 2015:

	Years Ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Weighted average common shares outstanding:			
Basic	147,320	134,755	119,926
Dilutive common stock options	3	-	25
Dilutive performance units	633	-	422
Diluted	147,956	134,755	120,373

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The following table is a summary of the performance units, which were not included in the computation of diluted net income per share, as inclusion of these items would be antidilutive:

	Years Ended December 31,		
(in thousands)	**2017**	**2016**	**2015**
Number of antidilutive common shares:			
Antidilutive performance units	81	-	-

Note 15. ***Other current liabilities***

The following table provides the components of the Company's other current liabilities atDecember 31, 2017 and 2016:

	December 31,	
(in millions)	**2017**	**2016**
Other current liabilities:		
Accrued production costs	$ 72	$ 63
Payroll related matters	40	35
Accrued interest	36	32
Settlements due on derivatives	25	-
Asset retirement obligations	12	10
Other	31	12
Other current liabilities	$ 216	$ 152

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Note 16. *Subsidiary guarantors*

At December 31, 2017, certain of the Company's 100 percent owned subsidiaries have fully and unconditionally guaranteed the Company's senior notes. The indentures governing the Company's senior notes provide that the guarantees of its subsidiary guarantors will be released in certain customary circumstances including (i) in connection with any sale, exchange or other disposition, whether by merger, consolidation or otherwise, of the capital stock of that guarantor to a person that is not the Company or a restricted subsidiary of the Company, such that, after giving effect to such transaction, such guarantor would no longer constitute a subsidiary of the Company, (ii) in connection with any sale, exchange or other disposition (other than a lease) of all or substantially all of the assets of that guarantor to a person that is not the Company or a restricted subsidiary of the Company, (iii) upon the merger of a guarantor into the Company or any other guarantor or the liquidation or dissolution of a guarantor, (iv) if the Company designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the indenture, (v) upon legal defeasance or satisfaction and discharge of the indenture and (vi) upon written notice of such release or discharge by the Company to the trustee following the release or discharge of all guarantees by such guarantor of any indebtedness that resulted in the creation of such guarantee, except a discharge or release by or as a result of payment under such guarantee.

See Note 9 for a summary of the Company's senior notes. In accordance with practices accepted by the SEC, the Company has prepared condensed consolidating financial statements in order to quantify the assets, results of operations and cash flows of such subsidiaries as subsidiary guarantors. In addition, two of the Company's subsidiaries do not guarantee the Company's senior notes and are included in the Company's consolidated financial statements. One of such entities is a VIE that was formed to effectuate a tax-free exchange of assets, and the other entity is a 100 percent owned subsidiary that was recently acquired. These entities are referred to as "Subsidiary Non-Guarantors" in the tables below.

The following condensed consolidating balance sheets at December 31, 2017 and 2016, condensed consolidating statements of operations and condensed consolidating statements of cash flows for the years ended December 31, 2017, 2016 and 2015, present financial information for Concho Resources Inc. as the parent on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for the subsidiary guarantors on a stand-alone basis (carrying any investment in non-guarantor subsidiaries under the equity method), financial information for the subsidiary non-guarantors on a stand-alone basis and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis. All current and deferred income taxes are recorded on Concho Resources Inc., as the subsidiaries are flow-through entities for income tax purposes. The subsidiary guarantors and subsidiary non-guarantors are not restricted from making distributions to the Company.

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Notes to Consolidated Financial Statements

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Condensed Consolidating Balance Sheet
December 31, 2017

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Entries	Total
ASSETS					
Accounts receivable - related parties	$ 8,836	$ (669)	$ -	$ (8,167)	$ -
Other current assets	6	576	10	-	592
Oil and natural gas properties, net	-	12,192	615	-	12,807
Property and equipment, net	-	234	-	-	234
Investment in subsidiaries	3,202	-	-	(3,202)	-
Other long-term assets	23	76	-	-	99
Total assets	$ 12,067	$ 12,409	$ 625	$ (11,369)	$ 13,732
LIABILITIES AND EQUITY					
Accounts payable - related parties	$ (669)	$ 8,223	$ 613	$ (8,167)	$ -
Other current liabilities	341	821	3	-	1,165
Long-term debt	2,691	-	-	-	2,691
Other long-term liabilities	789	166	6	-	961
Equity	8,915	3,199	3	(3,202)	8,915
Total liabilities and equity	$ 12,067	$ 12,409	$ 625	$ (11,369)	$ 13,732

Condensed Consolidating Balance Sheet
December 31, 2016

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
ASSETS				
Accounts receivable - related parties	$ 8,991	$ (336)	$ (8,655)	$ -
Other current assets	12	550	-	562
Oil and natural gas properties, net	-	11,086	-	11,086
Property and equipment, net	-	216	-	216
Investment in subsidiaries	1,989	-	(1,989)	-
Other long-term assets	11	244	-	255

Total assets	$	11,003	$	11,760	$	(10,644)	$	12,119
LIABILITIES AND EQUITY								
Accounts payable - related parties	$	(336)	$	8,991	$	(8,655)	$	-
Other current liabilities		113		640		-		753
Long-term debt		2,741		-		-		2,741
Other long-term liabilities		862		140		-		1,002
Equity		7,623		1,989		(1,989)		7,623
Total liabilities and equity	$	11,003	$	11,760	$	(10,644)	$	12,119

Concho Resources Inc.

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Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2017

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 2,566	$ 20	$ -	$ 2,586
Total operating costs and expenses	(129)	(1,366)	(17)	-	(1,512)
Income (loss) from operations	(129)	1,200	3	-	1,074
Interest expense	(145)	(1)	-	-	(146)
Loss on extinguishment of debt	(66)	-	-	-	(66)
Other, net	1,221	19	-	(1,221)	19
Income before income taxes	881	1,218	3	(1,221)	881
Income tax benefit	75	-	-	-	75
Net income	$ 956	$ 1,218	$ 3	$ (1,221)	$ 956

Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2016

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 1,635	$ -	$ 1,635
Total operating costs and expenses	(370)	(3,334)	-	(3,704)
Loss from operations	(370)	(1,699)	-	(2,069)
Interest expense	(202)	(2)	-	(204)
Loss on extinguishment of debt	(56)	-	-	(56)
Other, net	(1,710)	(9)	1,710	(9)
Loss before income taxes	(2,338)	(1,710)	1,710	(2,338)
Income tax benefit	876	-	-	876
Net loss	$ (1,462)	$ (1,710)	$ 1,710	$ (1,462)

Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2015

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total

Total operating revenues	$	-	$	1,804	$	-	$	1,804
Total operating costs and expenses		697		(2,174)		-		(1,477)
Income (loss) from operations		697		(370)		-		327
Interest expense		(213)		(2)		-		(215)
Other, net		(387)		(15)		387		(15)
Income (loss) before income taxes		97		(387)		387		97
Income tax expense		(31)		-		-		(31)
Net income (loss)	$	66	$	(387)	$	387	$	66

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Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2017

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Entries	Total
Net cash flows provided by operating activities	$ 145	$ 1,549	$ 1	$ -	$ 1,695
Net cash flows used in investing activities	-	(1,105)	(614)	-	(1,719)
Net cash flows provided by (used in) financing activities	(145)	(497)	613	-	(29)
Net decrease in cash and cash equivalents	-	(53)	-	-	(53)
Cash and cash equivalents at beginning of period	-	53	-	-	53
Cash and cash equivalents at end of period	$ -	$ -	$ -	$ -	$ -

Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2016

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Net cash flows provided by (used in) operating activities	$ (665)	$ 2,049	$ -	$ 1,384
Net cash flows used in investing activities	-	(2,225)	-	(2,225)
Net cash flows provided by financing activities	665	-	-	665
Net decrease in cash and cash equivalents	-	(176)	-	(176)
Cash and cash equivalents at beginning of period	-	229	-	229
Cash and cash equivalents at end of period	$ -	$ 53	$ -	$ 53

Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2015

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Net cash flows provided by (used in) operating activities	$ (1,394)	$ 2,924	$ -	$ 1,530
Net cash flows used in investing activities	-	(2,602)	-	(2,602)
	1,394	(93)	-	1,301

Net cash flows provided by (used in) financing activities								
Net increase in cash and cash equivalents		-		229		-		229
Cash and cash equivalents at beginning of period		-		-		-		-
Cash and cash equivalents at end of period	$	-	$	229	$	-	$	229

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Notes to Consolidated Financial Statements

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Note 17. *Subsequent events*

Southern Delaware Basin divestitures. In January 2018, the Company closed on two asset sales transactions of certain non-core assets in Reeves and Ward Counties with combined preliminary proceeds of approximately $280 million, subject to customary post-closing adjustments. As of December 31, 2017, the Company received cash deposits totaling approximately $29 million for the asset sales, which was included in the total cash flows from investing activities in its consolidated statement of cash flows. The assets divested included proved and unproved oil and natural gas properties on approximately 20,000 net acres. This completed the Reverse 1031 Exchange discussed in Note 4.

February 2018 nonmonetary transaction. In February 2018, the Company closed on a trade where it received approximately 21,000 net acres, primarily located in the Midland Basin, with current production of 5 MBoepd in exchange for approximately 34,000 net acres, primarily comprised of approximately 32,000 net acres in the northern Delaware Basin, with current production of 3 MBoepd.

New commodity derivative contracts. After December 31, 2017, the Company entered into the following oil price swaps, oil basis swaps and natural gas price swaps to hedge additional amounts of the Company's estimated future production:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Price Swaps: (a)					
2018:					
Volume (Bbl)	915,000	1,213,000	1,013,000	674,000	3,815,000
Price per Bbl	$ 63.64	$ 63.48	$ 63.34	$ 63.11	$ 63.42
2019:					
Volume (Bbl)	876,000	748,000	636,000	552,000	2,812,000
Price per Bbl	$ 58.14	$ 58.12	$ 58.10	$ 58.08	$ 58.11
2020:					
Volume (Bbl)	1,001,000	1,001,000	1,012,000	1,012,000	4,026,000
Price per Bbl	$ 54.80	$ 54.80	$ 54.80	$ 54.80	$ 54.80
Oil Basis Swaps: (b)					
2018:					

Volume (Bbl)		615,000		637,000		399,000		306,000		1,957,000
Price per Bbl	$	0.13	$	0.06	$	(0.07)	$	(0.10)	$	0.03
2019:										
Volume (Bbl)		180,000		182,000		184,000		-		546,000
Price per Bbl	$	(0.27)	$	(0.27)	$	(0.27)	$	-	$	(0.27)
2020:										
Volume (Bbl)		2,184,000		2,184,000		2,208,000		2,208,000		8,784,000
Price per Bbl	$	(0.09)	$	(0.09)	$	(0.09)	$	(0.09)	$	(0.09)
Natural Gas Price Swaps: (c)										
2018:										
Volume (MMBtu)		1,277,000		878,000		921,000		274,000		3,350,000
Price per MMBtu	$	3.08	$	3.08	$	3.08	$	3.08	$	3.08

(a) The index prices for the oil price swaps are based on the NYMEX – WTI monthly average futures price.

(b) The basis differential price is between Midland – WTI and Cushing – WTI.

(c) The index prices for the natural gas price swaps are based on the NYMEX – Henry Hub last trading day futures price.

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Unaudited Supplementary Data

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Capitalized costs

(in millions)	December 31, 2017	2016
Oil and natural gas properties:		
Proved	$ 18,565	$ 16,620
Unproved	2,702	1,856
Less: accumulated depletion	(8,460)	(7,390)
Net capitalized costs for oil and natural gas properties	$ 12,807 (a)	$ 11,086

(a) Approximately $135 million of the balance at December 31, 2017 relates to assets held for sale. See Note 17 for additional information.

Costs incurred for oil and natural gas producing activities

(in millions)	Years Ended December 31, 2017	2016	2015
Property acquisition costs:			
Proved	$ 303	$ 982	$ 57
Unproved	905	1,154	206
Exploration	1,021	701	1,123
Development	653	449	709
Total costs incurred for oil and natural gas properties	$ 2,882	$ 3,286	$ 2,095

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Unaudited Supplementary Data

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Results of operations for oil and natural gas producing activities

The following table provides results of operations for the Company's oil and natural gas producing activities and excludes amounts incurred from the Company's non-oil and gas producing activities for the years ended December 31, 2017, 2016 and 2015:

(in millions)	Years Ended December 31, 2017	2016	2015
Oil and natural gas producing activities:			
Operating revenues:			
Oil sales	$ 2,092	$ 1,350	$ 1,540
Natural gas sales	494	285	264
Total operating revenues	2,586	1,635	1,804
Operating costs and expenses:			
Oil and natural gas production	408	320	390
Production and ad valorem taxes	199	131	151
Exploration and abandonments	59	77	59
Depreciation, depletion and amortization	1,146	1,167	1,223
Accretion of discount on asset retirement obligation	8	7	8
Impairments of long-lived assets	-	1,525	61
General and administrative	244	226	231
(Gain) loss on derivatives	126	369	(700)
(Gain) loss on disposition of assets, net	(23)	(118)	54
Total operating costs and expenses	2,167	3,704	1,477
Income (loss) before income taxes	419	(2,069)	327
Income tax (expense) benefit at statutory rate	(154)	759	(122)
Net income (loss)	$ 265	$ (1,310)	$ 205

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Unaudited Supplementary Data

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Reserve Quantity Information

The following information represents estimates of the Company's proved reserves as of December 31, 2017. The pricing that was used for estimates of the Company's reserves as of December 31, 2017 was based on the SEC pricing of $47.79 per Bbl West Texas Intermediate posted oil price and $2.98 per MMBtu Henry Hub spot natural gas price. See table below.

Subject to limited exceptions, proved undeveloped reserves may only be recognized if they relate to wells scheduled to be drilled within five years of the date of their initial recognition. This rule limited, and may continue to limit, the Company's potential to record additional proved undeveloped reserves as it pursues its drilling program, particularly as it develops its significant acreage in the Permian Basin of southeast New Mexico and west Texas. Moreover, the Company may be required to write down its proved undeveloped reserves if it does not drill on those reserves within the required five-year timeframe. All of the Company's recorded proved undeveloped reserves are scheduled to be drilled within five years of the date of their initial recognition.

The Company's proved oil and natural gas reserves are all located in the United States, primarily in the Permian Basin of southeast New Mexico and west Texas. All of the estimates of the proved reserves at December 31, 2017, 2016 and 2015 are based on reports prepared by Cawley, Gillespie & Associates, Inc. and Netherland, Sewell & Associates, Inc., independent petroleum engineers. Proved reserves were estimated in accordance with the guidelines established by the SEC and the FASB.

The following table summarizes the prices utilized in the reserve estimates for 2017, 2016 and 2015. Commodity prices utilized for the reserve estimates prior to adjustments for location, grade and quality are as follows:

	December 31, 2017	December 31, 2016	December 31, 2015
Prices utilized in the reserve estimates before adjustments:			
Oil per Bbl	$ 47.79	$ 39.25	$ 46.79

Natural gas per MMBtu	$ 2.98	$ 2.48	$ 2.59

Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

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Unaudited Supplementary Data

December 31, 2017, 2016 and 2015

The following table provides a rollforward of the total proved reserves for the years ended December 31, 2017, 2016 and 2015, as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year.

	2017			2016			
	Oil and Condensate (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Oil and Condensate (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Oil and Condensate (MMBbls)
Total Proved Reserves:							
Balance, January 1	428	1,752	720	368	1,534	623	370
Purchases of minerals-in-place	22	72	34	41	109	59	7
Sales of minerals-in-place	(2)	(9)	(4)	(6)	(15)	(8)	(1)
Extensions and discoveries	115	351	174	84	247	125	97
Revisions of previous estimates	(20)	38	(14)	(25)	4	(24)	(71)
Production	(43)	(161)	(70)	(34)	(127)	(55)	(34)
Balance, December 31	500	2,043	840	428	1,752	720	368
Proved Developed Reserves:							
January 1	267	1,190	466	204	927	358	211
December 31	336	1,512	588	267	1,190	466	204
Proved Undeveloped Reserves:							
January 1	161	561	254	164	607	265	159
December 31	164	531	252	161	561	254	164

For the year ended December 31, 2017:

Purchases and sales of minerals-in-place. The Company’s purchases of minerals-in-place are composed of approximately 11 MMBoe from the July 2017 Midland Basin acquisition, 8 MMBoe from the January 2017 Northern Delaware Basin acquisition and 15 MMBoe from various other acquisitions throughout the year. The Company’s sales of minerals-in-place are composed of approximately 4 MMBoe from various divestitures throughout the year.

Extensions and discoveries. Extensions and discoveries of approximately 174 MMBoe are primarily the result of the Company's continued success from its extension and infill horizontal drilling programs in its core operating areas. Proved developed reserves increased approximately 82 MMBoe due to the Company's exploratory drilling activity in 2017. Based upon this activity, approximately 92 MMBoe of new proved undeveloped locations were added.

Revisions of previous estimates. Revisions of previous estimates are composed of (i) 61 MMBoe of negative revisions due to proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within five years of the date of their initial recognition as required by SEC rules due to a shift in the Company's capital program to generally focus more on large-scale development projects in certain areas, (ii) 29 MMBoe of positive price revisions and (iii) 18 MMBoe of positive technical and performance revisions. Our proved reserves at December 31, 2017 were determined using the SEC pricing of $47.79 per Bbl WTI posted oil price and $2.98 per MMBtu Henry Hub spot natural gas price, as compared to corresponding prices of $39.25 per Bbl of oil and $2.48 per MMBtu of natural gas at December 31, 2016.

For the year ended December 31, 2016:

Purchases and sales of minerals-in-place. The Company's purchases of minerals-in-place are composed of approximately 42 MMBoe from the October 2016 Reliance Acquisition, 15 MMBoe from the March 2016 Southern Delaware Basin acquisition and 2 MMBoe from various other acquisitions throughout the year. The Company's sales of minerals-in-place are composed of approximately 8 MMBoe from various divestitures throughout the year.

Extensions and discoveries. Extensions and discoveries of approximately 125 MMBoe are primarily the result of the Company's continued success from its extension and infill horizontal drilling programs in its core operating areas. Proved developed reserves increased approximately 61 MMBoe due to the Company's exploratory drilling activity last year. Based upon this activity, approximately 64 MMBoe of new proved undeveloped locations were added, of which the majority are one offset location from an existing producing well.

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Revisions of previous estimates. Revisions of previous estimates are comprised of (i) 57 MMBoe of negative revisions due to proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within five years of the date of their initial recognition and (ii) 30 MMBoe of negative price revisions, partially offset by 63 MMBoe of net positive revisions related to lower lease operating expense estimates. The 57 MMBoe of proved undeveloped reserves in item (i) above are outside the five-year development window primarily due to results the Company has obtained during 2016 related to increased testing and implementation of new technologies that allows for drilling extended length laterals. The results are generally highly successful and provide sufficient data that substantiates drilling extended length laterals is generally a more efficient process than shorter lateral drilling to recover reserves. The results also generally confirm that the drilling of longer laterals is feasible on a large scale and substantially decreases the risks associated with a drilling program more focused on extended length laterals. Consequently, the Company shifted its capital program to focus on drilling more extended length laterals.

For the year ended December 31, 2015:

Purchases and sales of minerals-in-place. The Company’s purchases of minerals-in-place are composed of approximately 12 MMBoe from various acquisitions throughout the year and 2 MMBoe from various divestitures throughout the year.

Extensions and discoveries. Extensions and discoveries of approximately 157 MMBoe are primarily the result of the Company’s continued success from its extension and infill horizontal drilling programs in its core operating areas. There were approximately 55 MMBoe of proved developed reserves that were directly added through the Company’s drilling activity last year. Based upon this activity, approximately 102 MMBoe of new proved undeveloped locations were added, of which the vast majority are one offset location from an existing producing well.

Revisions of previous estimates. Revisions of previous estimates are comprised of (i) 112 MMBoe of negative price revisions, (ii) 11 MMBoe of negative revisions due to proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within the five years of the date of their initial recognition required by SEC rules and (iii) 6 MMBoe net negative revision resulting from technical and performance evaluations.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is computed by applying the 12-month unweighted average of the first-day-of-the-month pricing for oil and natural gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and natural gas reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and natural gas properties plus available carryforwards and credits and applying the current tax rates to the difference.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and natural gas properties. Estimates of fair value would also consider probable and possible reserves, anticipated future oil and natural gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

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The following table provides the standardized measure of discounted future net cash flows at December 31, 2017, 2016 and 2015:

(in millions)	December 31, 2017	2016	2015
Oil and gas producing activities:			
Future cash inflows	$ 29,761	$ 20,674	$ 20,133
Future production costs	(9,612)	(7,945)	(7,667)
Future development and abandonment costs (a)	(2,636)	(2,458)	(3,357)
Future income tax expense	(2,565)	(1,382)	(1,119)
Future net cash flows	14,948	8,889	7,990
10% annual discount factor	(7,470)	(4,699)	(4,251)
Standardized measure of discounted future net cash flows	$ 7,478	$ 4,190	$ 3,739

(a) Includes $256 million, $231 million and $197 million of undiscounted asset retirement cash outflow estimated at December 31, 2017, 2016 and 2015, respectively, using current estimates of future abandonment costs less salvage values. See Note 5 for corresponding information regarding the Company's discounted asset retirement obligations.

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table provides a rollforward of the standardized measure of discounted future net cash flows for the years ended December 31, 2017, 2016 and 2015:

(in millions)	Years Ended December 31, 2017	2016	2015
Oil and natural gas producing activities:			
Purchases of minerals-in-place	$ 304	$ 497	$ 74
Sales of minerals-in-place	(20)	(62)	(5)
Extensions and discoveries	2,014	1,116	1,022

Development costs incurred during the period	619	278	464
Net changes in prices and production costs	1,830	(935)	(7,893)
Oil and natural gas sales, net of production costs	(1,979)	(1,184)	(1,263)
Changes in future development costs	84	591	988
Revisions of previous quantity estimates	(154)	(189)	(1,125)
Accretion of discount	470	405	1,065
Changes in production rates, timing and other	470	62	(449)
Change in present value of future net revenues	3,638	579	(7,122)
Net change in present value of future income tax expense (benefit)	(350)	(128)	2,838
	3,288	451	(4,284)
Balance, beginning of year	4,190	3,739	8,023
Balance, end of year	$ 7,478	$ 4,190	$ 3,739

Concho Resources Inc.

Unaudited Supplementary Data

December 31, 2017, 2016 and 2015

Selected Quarterly Financial Results

The following table provides selected quarterly financial results for the years ended December 31, 2017 and 2016:

	Quarter			
(in millions, except per share data)	**First**	**Second**	**Third**	**Fourth**
Year ended December 31, 2017:				
Total operating revenues	$ 612	$ 567	$ 627	$ 780
Operating costs and expenses (excluding gains (losses) on derivatives and gains on disposition of assets, net)	(491)	(507)	(511)	(555)
Gains (losses) on derivatives	286	209	(206)	(415)
Gains on disposition of assets, net	654	-	13	11
Income (loss) from operations	$ 1,061	$ 269	$ (77)	$ (179)
Income tax (expense) benefit	$ (371)	$ (93)	$ 66	$ 473
Net income (loss)	$ 650	$ 152	$ (113)	$ 267
Earnings per common share - Basic	$ 4.39	$ 1.02	$ (0.77)	$ 1.80
Earnings per common share - Diluted	$ 4.37	$ 1.02	$ (0.77)	$ 1.79
Year ended December 31, 2016:				
Total operating revenues	$ 284	$ 396	$ 430	$ 525
Operating costs and expenses (excluding gains (losses) on derivatives)	(1,918)	(467)	(469)	(481)
Gains (losses) on derivatives	81	(298)	41	(193)
Income (loss) from operations	$ (1,553)	$ (369)	$ 2	$ (149)
Net loss	$ (1,020)	$ (266)	$ (51)	$ (125)
Earnings per common share - Basic	$ (7.95)	$ (2.04)	$ (0.38)	$ (0.86)
Earnings per common share - Diluted	$ (7.95)	$ (2.04)	$ (0.38)	$ (0.86)

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